DEEP PLACEMENT GEL BANK AS AN IMPROVED OIL RECOVERY PROCESS: MODELING, ECONOMIC ANALYSIS AND COMPARISON TO POLYMER FLOODING

A Thesis

by

MURAD SEYIDOV

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

May 2010

Major Subject: Petroleum Engineering

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Approved by:

Chair of Committee,	Robert H. Lane
Committee Members,	Daulat D. Mamora
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ABSTRACT

Deep Placement Gel Bank as an Improved Oil Recovery Process: Modeling, Economic Analysis and Comparison to Polymer Flooding.

(May 2010)

Murad Seyidov, B.S., Azerbaijan State Oil Academy

Chair of Advisory Committee: Dr. Robert H. Lane

Many attempts have been made to control water conformance. It is very costly to produce, treat and dispose of water, and produced water represents the largest waste stream associated with oil and gas production. The production of large amounts of water results in: (a) the need for more complex water–oil separation; (b) corrosion of wellbore and other equipment; (c) a rapid decline in hydrocarbon production rate and ultimate recovery; and (d) consequently, premature abandonment of a well or field, leaving considerable hydrocarbons unproduced.

Sometimes water production results from heterogeneities in the horizontal direction, which leads to uneven movement of the flood front and subsequent early breakthrough of water from high permeability layers. This problem is exacerbated if there is (vertical) hydraulic communication between layers so that crossflow can occur.

One of the novel technologies in chemical enhanced oil recovery (EOR) is a gel type called deep diverting gel (DDG), which describes material that functions by plugging thief zones deep from the well where they were being injected. To evaluate the performance of this new treatment method, we will (1) model the treatment methods, (2) conduct economic analysis, and (3) compare different EOR methods.

We have conducted relevant literature review about the development, design, modeling and economics of the enhanced oil recovery methods. Schlumberger's Eclipse simulator software has been used for modeling purposes.

Modeling runs have demonstrated that placement of a DDG in a high permeability zone provided a blockage that diverted water into lower permeability areas, thus increasing the sweep of target zones. Research results demonstrated that, although higher recovery can be achieved with a polymer flood, the combination of delayed production response and large polymer amounts cause such projects to be less economically favorable than deep gel placement treatments. From results of several sensitivity runs, it can be concluded that plug size and oil viscosity are two determining factors in the efficiency of DDG treatments.

For the assumed case, economic analysis demonstrated that DDG has the most positive net present value (NPV), with polymer flooding second and simply continuing the waterflood to its economic limit the least positive NPV.

DEDICATION

This work is dedicated to my family, especially my Mother for continuous support and encouragement.

ACKNOWLEDGEMENTS

I wish to express my sincere appreciation to the members of my graduate advisory committee for their contribution and continuous support to accomplish this research.

Thank you to the chairman of my graduate advisory committee, Dr. Robert H. Lane, for his endless support, understanding and continuous assistance in bringing this research to completion.

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Thanks also to faculty and staff of the Harold Vance Department of Petroleum Engineering at Texas A&M University for providing the necessary facilities and accommodations to conduct my research.

Finally, I would like to thank BP Azerbaijan for giving me this opportunity to pursue my M.S. degree in a pioneer university in the petroleum industry.

NOMENCLATURE

S_{dpv}	dead pore space within each grid cell
C_a	adsorption isotherm which is a function of the local polymer solution concentration
ρ_r	mass density of the rock formation
Φ	porosity
ρ_w	water density
Σ	sum over neighboring cells
R_k	relative permeability reduction factor for the aqueous phase due to polymer retention
C_p	local concentration of polymer
C_n	sodium chloride in the aqueous phase
$\mu_{a\mathrm{eff}}$	effective viscosity of the water (a=w), polymer (a=p) and salt (a=s)
D_z	cell center depth.
B_r	rock formation volume
B_w	water formation volume
T	transmissibility
k_{rw}	water relative permeability
S_w	water saturation
V	block pore volume
Q_w	water production rate
P_w	water pressure

g	gravity acceleration
NPV	Net Present Value

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I INTRODUCTION

1.1 Statement of Problem

Conformance challenges have always been an issue for petroleum engineers. For several decades, engineers have applied various improved methods to overcome high water production problems to increase oil recovery.

In reservoirs where large vertical permeability differences exist among its connected layers, high permeability zones can be an offensive feature, especially during water flooding projects. Early water breakthrough from a high permeability layer reduces the sweep efficiency of the injection process and bypasses a significant amount of hydrocarbons.

For several decades, polymer has been added to improve the mobility ratio in the effort to increase oil recovery efficiency in water flood projects. The main objective of a polymer flood is to reduce the mobility ratio by increasing injection water viscosity. This results in a more uniform flood front, thus higher oil recovery in less time and less water handling costs.

High cost is a major drawback of the polymer injection method, since polymer must be injected for long periods of time to achieve high efficiency. It is also costly because enough polymer must be used to yield a drive fluid with a minimum viscosity of approximately ten times that of the injected water.

Engineers have been working on developing more cost effective and less

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This thesis follows the style of *SPE Reservoir Evaluation and Engineering.*

restrictive methods. One approach has been to inject a low viscosity material with the ability to form a blocking phase at some distance from the injection wellbore. Water flood modification by reducing the permeability of a highly perm streak should result in a system where most injected material is used to achieve better sweep efficiency.

A novel technology in this area is in-depth blockage gel, also called Deep Diverting Gels (DDG). An early version of this concept has been colloidal dispersion gel (CDG) (Mack 1994). A similar material developed by a major international oil company was field tested at Kuparuk Field, Alaska for the first time (Sydansk et al. 1994). This approach involves injecting a dilute solution of polyacrylamide polymer with a slow crosslinking agent such as aluminum citrate or chromium(III) acetate.

A more recent development is the use of an internally crosslinked polymer that expands to form a blocking phase far from the injection well. This concept was developed by an industry consortium (Frampton et al. 2004). The blocking material is injected as a slurry of sub-micron particles that can be injected into the reservoir far from an injection well. Eventually polymer particles expand and plug pore throats to form a blocking phase. Temperature and time are control parameters for “activation” of this "popcorn" effect of the internally crosslinked polymer.

In 2001, the first of these water flood profile modification treatments was pumped in the Minas Field located on the island of Sumatra in Indonesia (Pritchett et al. 2003). This and several other applications of this method lead to an improvement in production performance. However, there has been little published material about this method, (Pritchett et al. 2003, Frampton et al. 2004, Bai et al. 2008), especially how it compares to polymer flood and water flooding in terms of production and economics.

1.2 Research Objectives

Some work has been done comparing the application of Deep Diverting Gels with other 'conventional' flooding methods. (Coste et al. 2000, Seright et al. 1995., Smith 1995) However there are few publications available on this issue as a base for deeper research. As this treatment is becoming more widely used as an improved oil recovery technique, there is more need for research demonstrating differences among chemical IOR and EOR methods.

In this research, we will model the process of DDG injection during water flooding, since that option is not available on commercial software. The model will make available 3D views of the reservoir for better understanding of the process. Schlumberger's Eclipse simulator will be used for modeling the treatment.

This research is a computational method of evaluation and does not include lab work, which may have given more precise data on the effectiveness of a blocking phase. Unknown parameters have been assumed based on previous applications and common field occurrences. The main purpose of this research is to illustrate expected results from the application of DDG to ideal reservoir and compare the results to those of other flooding methods.

The specific objectives of this research are to:

- Model Deep Diverting Gel application to the reservoir
- Run sensitivities for a wide range of conditions

- Perform an economic analysis for a reasonable DDG process
- Model other flooding methods on the same ideal model for comparison

1.3 Outline of Thesis

This thesis has been constructed as a progression of work - from a discussion of theoretical background to model development and, later, a presentation of results. Generalized themes of each section will be shown in the coming paragraphs of this outline.

Review and analysis of previous literature is presented in Section 2 of the thesis. There we include information about the causes of high water cut problems and possible solutions for it.

In Section 3, we explain more broadly the theory behind the deep diverting gels, since the main purpose of this research is to compare this type of polymer/gel treatment to other types of treatments.

In Section 4, simulation modeling approach will be introduced. Data inputs, utilized software, and the construction of the reservoir will be discussed in this section. Also there will be consideration of challenges observed and overcame during this process.

Results and discussions of simulation runs, including tables and plots, will be demonstrated in Section 5.

In Section 6, results of extra sensitivity runs for deep diverting gel treatment optimization can be found.

We conduced basic economic analysis in order to compare water flooding, polymer flooding and deep diverting gels financially. Results and plots of this analysis are shown in Section 7.

In Section 8, we detail our conclusions from this study and make recommendations for future work.

II LITERATURE REVIEW

2.1 Water Production

Causes of excessive water production can be divided into several categories such as mechanical, completion related, and reservoir related problems.

2.1.1 Mechanical Problems

Holes from corrosion, wear and splits due to flaws, formation deformation, excessive pressure, etc. represent problems caused by the poor integrity of the casing. Often casing leaks occur where there is no cement behind the casing (Reynolds et al. 2003). Casing leaks are pathways for unwanted water and they lead to an unexpected rise in water production. In addition, the water entry in the wellbore can cause damage to the producing formation due to fluid invasion. Generally, mechanical problems are due to poor mechanical integrity.

2.1.2 Completion Problems

Common completion related problems are caused by the channels behind the casing, completion into or close to water zone, and fracturing out of zone.

Channels Behind Casing

Channels behind casing can result from poor cement-casing or from cement-formation bonds (Reynolds et al. 2003) (Figure 1). These channels are most likely to occur immediately after the well is completed or stimulated, but they sometimes can develop throughout the well's life.

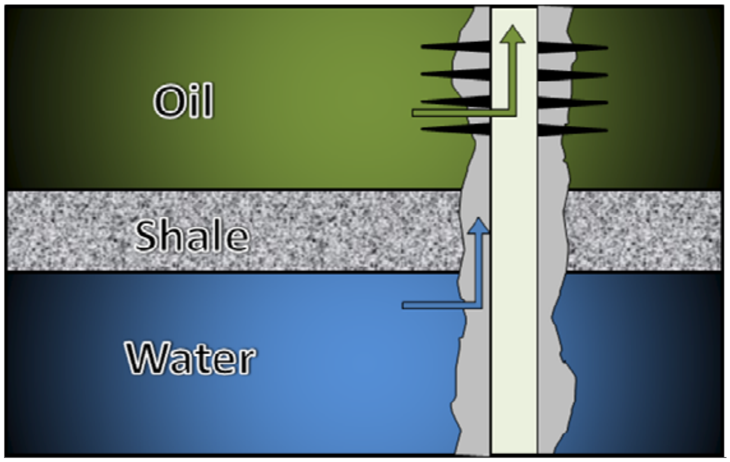

Figure 1: Water production through channels behind casing

Completion Into or Close to Water Zone

Immediate production of water occurs when the well is completed into the zones where water saturation is higher than the irreducible water saturation. Often, impermeable barriers (e.g., shale) separate hydrocarbon-bearing strata from water saturated zones that could be the source of excess water production. However, due to the higher dragging force around the wellbore, the barriers can break down and allow fluid to migrate through the wellbore (Figure 2). Even if perforations are above the original water-oil contact, proximity allows water production to occur easily and quickly through coning or cresting (Aminian 2009).

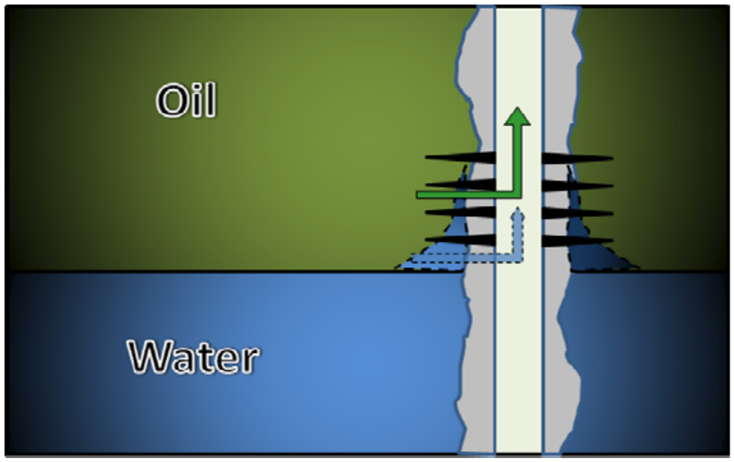

Figure 2: Water production from perforations close to the source

Fracturing Out of Zone

Fractures into water zones often occur accidentally during necessary hydraulic fracturing of the wells (Azari et al. 1997) (Figure 3). In such cases, coning through hydraulic fracture can result in a significant rise in water production. In addition, stimulation treatments can cause barriers to collapse near the wellbore as mentioned above.

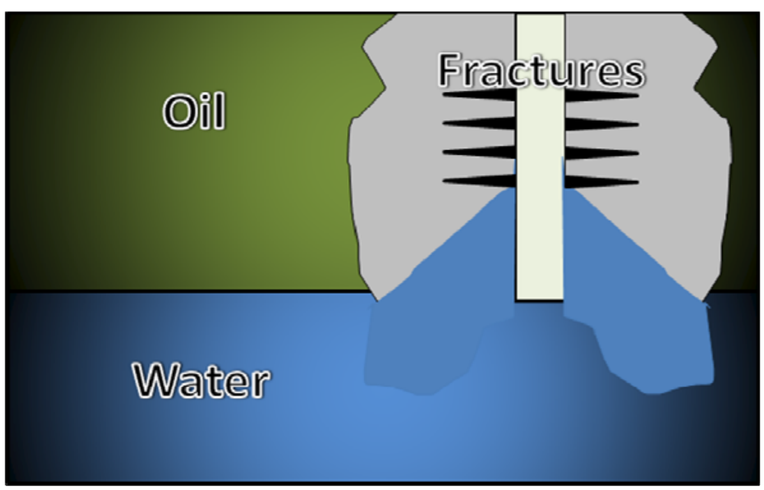

Figure 3: Water production through fractures

2.1.3 Reservoir Problems

These are the problems that are caused by the nature of the reservoir. The main reservoir related problems are channeling, coning, and depletion.

Channeling

Fractures or fracture-like features in the reservoir are the most common cause of channeling. Reservoir heterogeneities leading to the presence of highly permeable streaks cause water channeling (Figure 4). Water production could also be driven via natural fractures from underlying aquifers. Deviated and horizontal wells are prone to intersect faults or fractures and are in danger of excess water production if these faults or fractures connect to an aquifer. In unfractured reservoirs permeability variations between various layers associated with stratification can result in channels between an injector and a producer or from an edge water aquifer to the producers.

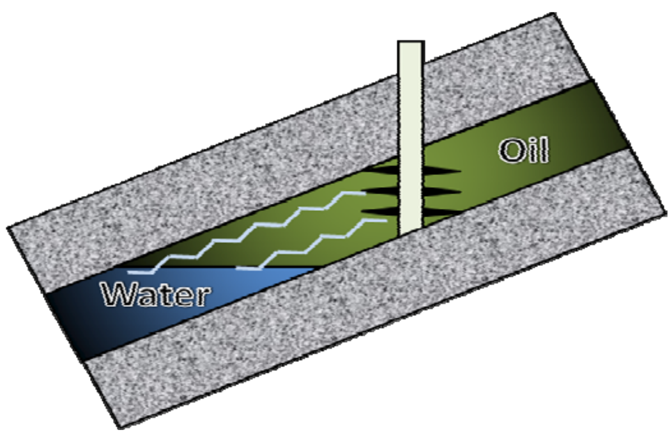

Figure 4: Channeling

Coning

Water coning is caused by vertical pressure gradients near the well. The well is produced so rapidly that viscous forces overcome gravitational forces and draw the water from a lower connected zone toward the wellbore (Figure 5). Eventually, the water can break through into the perforated or open-hole section, replacing all or part of the hydrocarbon production. Once breakthrough occurs, the problem worsens as higher cuts of the water are produced. Although reduced production rates can curtail the problem, they cannot cure it. Cusping in an inclined zone up to a vertical well, and water cresting in horizontal wells are similar phenomena to water coning.

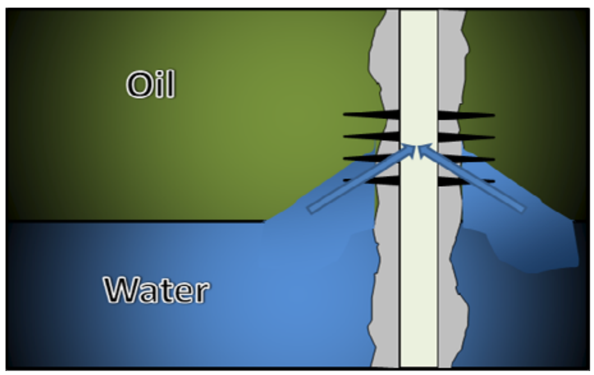

Figure 5: Coning

Reservoir Depletion

Water production is an expected consequence of oil or gas production. Not much can be done to decrease water production in a depleted reservoir. Generally, at the later stages of production, the focus of water control will shift from preventing water production to reducing the cost of produced water (Azari et al 1997).

2.1.4 Consequences

Water production is one of the main technical, environmental, and economical problems in oil and gas production. Water production reduces the productive life of oil and gas wells, and it can cause severe difficulties for oil production including corrosion of tubing and hydrostatic loading. High water production can lead to an:

- increase in pumping costs (lifting and re-injection)
- increase in oil/water separation costs
- increase in platform size/equipment costs
- increase in corrosion, scale, and sand-production treatment costs
- increase in environmental damage/liability
- reduction in oil production rate by increasing fluid levels and down hole pressures
- reduction in reservoir sweep efficiency.
- decrease in the economic life of the reservoir and ultimate recovery.
- increase in formation damage.

In the United States, eight barrels of water are produced for every barrel of oil. This is the largest waste stream associated with oil and gas production. The environmental impact of handling, treating and disposing of the excess water can have a serious effect on the profitability of oil and gas production. As of 2003, the annual cost of disposing of the produced water in the United States was estimated to be 5-10 billion dollars (Seright et al. 2003).

2.2 Improved Recovery Methods

In primary recovery, oil is driven to the production well by natural reservoir energy. Any method that improves oil production beyond the primary recovery is referred as enhanced oil recovery. Secondary recovery refers to any EOR process that does not involve a chemical reaction between the injected fluid and the oil in the reservoir (Stosur et al. 2003). Pressure maintenance techniques, such as water or gas injection and polymer flooding, are among the widely applied secondary recovery processes.

2.2.1 Water Flooding

The lack of sufficient natural drive in most reservoirs has led to the practice of supplementing natural reservoir energy with some form of artificial drive. The most basic example of this is the injection of gas or water to create sufficient drive.

Water flooding is perhaps the most common method of secondary recovery. Relatively cheap cost and an increase in ultimate recovery make water flooding one of the most favorable secondary recoveries for companies. The injection of water, however, may present problems like channeling, coning on horizontal wells, breakthrough from high permeability streaks, and, overall, high water-oil ratio during production. Within any reservoir, permeability variations, either vertical or aerial, stimulate the formation of water pathways. Once a continuous outlet exists, there is less incentive for the injected water to follow an alternative route. Consequently, the injected water, instead of pushing the remaining oil from the reservoir, simply bypasses it and flows through the easiest path. As an end result - and undesirable outcome - the production well delivers more water than oil, and the efficiency of the process gradually diminishes.

2.2.2 Polymer Flooding

For many reservoirs, polymer flooding is an attractive alternative to conventional water flooding, since relatively minor modifications to a water flood system are necessary to enable polymer injection and recover additional oil. The addition of polymers to injected water can increase oil recovery not only by improving vertical and areal sweep, but also by altering the water-oil fractional flow properties toward more efficient oil displacement. Polymers are used as a tool for mobility control to improve sweep efficiency and final oil recovery of water flood projects. A basic principle of fluid displacement is that the efficiency of the displacement increases with decreasing mobility (or increasing viscosity) of the displacing phase. This is also a basic principle of polymer flooding. For a given distance of viscous fluid penetration into a high permeability zone, the distance of penetration into less permeable zones becomes greater with increased viscosity or resistance factor of the injected fluid (Seright et al.1988). This concept is illustrated in Figure 6, demonstrating the distance of penetration in low permeability layers when the polymer penetrates 50 ft in a high permeability layer. This effect must be considered while designing the polymer flooding, for the concentration and viscosities of the polymer should be selected accordingly.

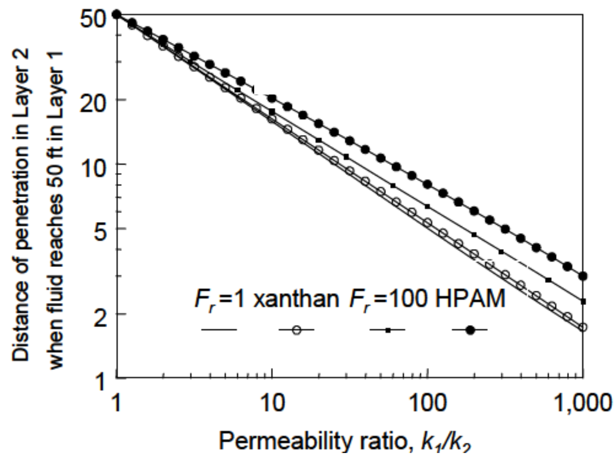

Figure 6: Rheology effect on penetration (Zhang et al. 2007)

A commonly accepted technique for evaluating polymer flood potential for a particular reservoir is by simulation of water flood and polymer floods under varying conditions and comparison of resulting oil recoveries. For the simulation to realistically portray reservoir response to polymer, it must include all significant properties of the polymer-reservoir system. Inputs of the simulation parameters will be discussed in the following chapter.

Most polymer floods use polyacrylamides and biopolymers. Polymer flooding is very sensitive to oil price, therefore this method's peak in the United States was in the 1980s when oil price was high enough to support it.

2.2.3 Squeeze Cementing

Cementing offending features is a mechanic solution for problems related to water flooding. Even though our research is expected to relate to chemical EOR methods, cement treatment will be considered as a possible solution in the sensitivity analysis.

Because of economic considerations and familiarity with the product, the first method usually attempted in resolving a conformance control problem is squeeze cementing. Formation pressure and fracturing pressure are the most important and useful information needed to design a successful zone isolation with cement treatment. Such information is useful to (1) avoid loss of a large volume of cement slurry into the formation, (2) determine realistic column height for recementing treatments, and (3) control cement fallback. From pressure buildup analysis and injectivity tests, it can be determined whether a well can hold a full column of fluid. Down hole pressure gauges should be used if formation pressure is not high enough to maintain a full column of liquid in the well. If a program requires circulating cement into an open annulus, formation pressure data and a series of "rate-in, rateout" circulation tests can be used to evaluate (1) perforation location, (2) realistic cement column height, and (3) the need for additional cleaning, foamed flushes, or application of ultra light foam cement.

A high incidence of first squeeze failures has gone a long way toward eliminating the phrase "simple squeeze job", A squeeze job failure is usually caused by a failure to place enough slurry in the areas where it can be effective, and hold it there long enough to form a permanent seal.

The most common reasons for undertaking cement squeezes are to:

- repair unsuccessful primary cement jobs (e.g., where primary cementing resulted in channeling or insufficient height of the cement column)
- seal off water-producing intervals
- repair casing leaks caused by corrosion or split pipe

- select plugging or isolation of perforations to control water injection profiles
- plug and abandon a depleted or watered-out producing zone

As can be noted from above uses, this method is quite effective in solving water production problems due to annular fluid migration, holes in casing, channels on primary cement sheath, and coning. For cases where further treatment from near wellbore region required, cement squeeze may not be as useful, though some engineers consider blocking the offending region with cement as a solution for excessive water production from high permeability streaks. Due to this there will be a simulation run including zone isolation for comparison with other methods.

2.2.4 Deep Diverting Gels

In the global context of growing energy needs and considering the depletion of oil and gas resources, extending the life of hydrocarbon reservoirs will be a challenge for decades to come. In this situation, significantly reducing water production and improving oil recovery efficiency is an important goal for the oil industry. Thus the development of more reliable techniques for water-shutoff, conformance, and mobility control is of crucial interest.

Polymer gels are designed to reduce the effects of reservoir heterogeneity beyond the wellbore and are usually placed near wellbore of production or injection wells to correct inter-layer heterogeneity or heal fracture. The basic premise of any gel technology is that the pre-gel solution, or gelant, will preferentially enter high permeability anomalies responsible for low volumetric sweep efficiency. Theoretically, once the gels reduce the flow capacity in the “thief zones”, areal and vertical sweep efficiency will improve. In cases where these zones are too far away from the wellbore and begin producing excessive amounts of the water as reservoir matures, the remaining oil on the thick heterogeneous layer becomes the most important target to improve oil recovery. In these cases, conventional polymer treatments should be improved to reach those zones.

Among the methods available to reduce water production on the cases described above, injecting a gelling system composed of a polymer and a crosslink has been widely used. These gelling systems are called in-depth diversion gels and are able to penetrate deeply into higher permeability zones or fractures and seal, or partially seal them off, thus creating high flow resistance in former, watered-out, high permeability portions of the zones. One of the major deep penetrating gels is Colloidal Dispersion Gel (CDG), which is obtained by crosslinking low concentration polymer solutions with low amounts of chromium acetate or aluminum citrate. This process slows down the gelation kinetics, so that, on a well injection time scale, those systems only form separate gel bundles, thus making it possible to enter the matrix rock. In this process, the gel is formed in-situ. Since gelling properties have been found to depend on many factors (Broseta et al. 2000), the gelling time, the final gel strength, and the depth of gel penetration is quite difficult to predict. This difficulty results from the uncertainties concerning different factors: shear stresses both in surface facilities and in near-wellbore area and also in the physico-chemical environment around the well (pH, salinity and temperature). Moreover, both polymer and/or crosslinker adsorption in the near-wellbore region and dilution by dispersion during CDG placement can affect the effectiveness of the treatment.

III THEORETICAL BACKGROUND OF DEEP DIVERSION GELS

The recovery factor of water flooding and other enhanced recovery operations in heterogeneous reservoirs that contain high permeability streaks can be increased by the application of gelled polymer treatments. Depth of the propagation and strength of the formed immobile gel structure are major factors influencing the success of such treatments. It has been shown that (Abdo et al. 1984) in-depth placement of gels has a significant role in the incremental oil recoveries of water flooding projects. The use of a partially hydrolyzed polyacrylamide/aluminum citrate colloidal dispersion gel (CDG) has been claimed (Mack et al.1994) to produce long-term, in-depth permeability modification in certain reservoirs, resulting in considerable incremental oil recoveries.

Gelants consist of an aqueous solution with one or more reactive components (e.g., a polymer, a crosslinker). The gelant components react to form an immobile gel. Straightforward applications of the Darcy equation and fractional-flow theory can quantify the distance of gelant penetration into a given zone. These calculations demonstrate that gelants can penetrate to a significant degree into all open zones—not just those zones with high water saturations (Seright et al.). Thus, if precautions (such as zone isolation) are not taken during gelant placement in unfractured wells (i.e., radial flow), low-permeability zones can be seriously damaged even in extremely heterogeneous reservoirs.

When a polymer-metal ion reacting solution is displaced through a set of five 100-mesh screens by applying a fixed pressure, the pre-gel aggregates were detected using a screen viscometer. The term “colloidal dispersion gel” was introduced (Mack et al.1994) to identify those aggregates. According to Mack and Smith (1994), the reacting solution is a colloidal dispersion gel when a gelatinous mass accumulates on the exit side of a screen viscometer when the pressure drop across the screens is less than a specific value, termed the "transition pressure," as shown in Figure 7. The existence of a transition pressure demonstrates that, under low pressure gradients, gel aggregates can be retained in a porous matrix. Figure 8 shows a gel aggregate mass accumulating on the exit of the screen viscometer (Al-Assi et al.2009).

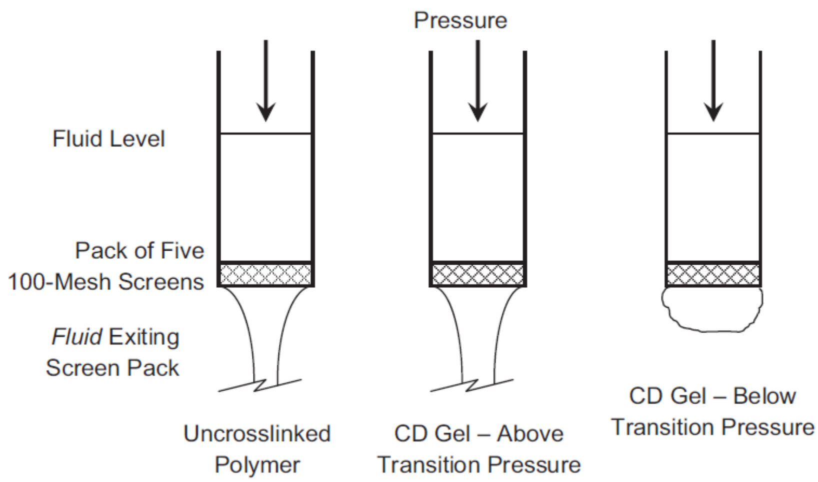

Figure 7: CDG flow through screen pack (Al-Assi et al. 2009)

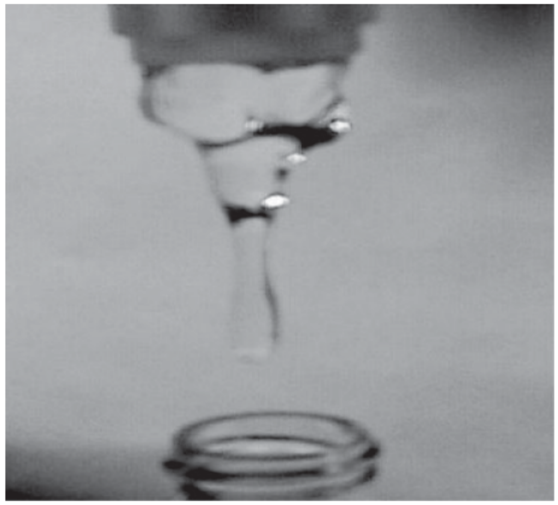

Figure 8: Flow of polymer-aluminum gel system out of the screen pack with pressure less than the transition pressure (Al-Assi et al. 2009)

When metal ions such as Cr^{3+}, Fe^{3+}, Al^{3+}, and Zr^{4+} are added to a partially hydrolyzed polyacrylamide solution, a reaction occurs between the carboxyl group and the metal ion. The early reaction is termed the “uptake reaction” and may take place at several possible sites on a single polymer molecule.

Polyacrylamide molecules are flexible coils in dilute solutions and are isolated from each other when the polymer concentration is less than C - the critical overlap concentration. If a further reaction occurs between the initial metal ion-carboxyl complex and another carboxyl group on the same polymer chain, intra-molecular crosslinks form. Due to additional metal ion complexes reacting with the polymer chain, the average molecular weight of the metal ion-polymer complex, termed a pre-gel aggregate, increases slightly. Unless the concentration of pre-gel aggregates exceeds C*, a gel structure cannot form. Aggregates can be filtered from solutions, leading to a concentrated gelatinous mass.

When the polymer concentration exceeds C, intermolecular crosslinks can occur between two or more polymer molecules, and the molecular weight of each complex increases in proportion to the extent of crosslinking. Continued intermolecular crosslinking may lead to the formation of an infinite network of crosslinks between polymer-metal ion complexes, leading to the formation of a gel and the immobilization of the solution. The onset of gelation is often detected by visual observations of bottles containing the reacting mixtures or by measuring the viscosity of the reaction mixture.

The aggregates are colloidal dispersions that remain stable but may grow in size depending upon the concentration of metal ion and polymer. Aggregates are created after aqueous polymer solution mixes with aluminum, and they can be identified by the scattering of a light beam passed through the solution. A continuous gel structure can be formed in the solution at certain polymer and aluminum concentrations within a narrow pH range in the vicinity of pH 6 and this solution would not be termed as "colloidal dispersion gel" any more.

The size of CDG aggregates is not known. Methods used to estimate the size of CDG aggregates include freeze drying followed by SEM analysis and size analysis by TEM. In these methods, measurements are compromised by artifacts introduced in the sample preparation and are considered unreliable. Determination of average molecular weight by low-angle laser light scattering (LALLS) has been demonstrated for chrome-carboxyl HPAM aggregates (Chang et al. 2002). However, this technique is labor intensive and requires exceptional patience and experimental skill. Direct estimation of the size of aluminum-HPAM gel aggregates has not been reported in the literature. Consequently, aggregate size is commonly inferred from indirect measurements such as solution viscosity.

The polyacrylamide/aluminum citrate CDG system, developed by Tiorco Inc., consists of low concentrations of HiVis 350, a partially hydrolyzed polyacrylamide with a viscosity average molecular weight of 27 million, and Tiorco 677, a chelated aluminum citrate solution. Typical concentrations used in this system are 300 ppm polymer and 15 ppm Al^{+3}. This system is reported to be slow forming, thus allowing for in-depth permeability treatment of oil reservoirs. It is hypothesized that polymer colloids, or gel aggregates, are formed and then filtered from the solution by the porous media, thereby reducing the permeability. These claims are based on interpretation of field performance in which large volumes of colloidal dispersed gel have been injected into petroleum reservoirs.

3.1 Effect of Viscosity

There have been several studies related to properties of propagation and settlement of gels. Seright and Liang (1993) conducted a research about the rheology of different types of blocking agents and Table 1 compares the selectivities in entering high- versus low-permeability zones. Each entry in Table 1 lists the distance of the blocking agent's penetration (in linear flow) into one zone relative to the distance of penetration into an adjacent zone ten times more permeable. Water injection is assumed to result in a unit-mobility displacement in this example. For each material, one case does not allow crossflow between layers, while a second case permits free crossflow between the layers

(Seright et al. 1995). The values in Table 1 are meant to illustrate what could happen (i.e., the extremes of behavior), not necessarily what will happen in every case.

Table 1 Comparison of placement properties in a two-layer linear system with a 1:10 permeability contrast (Seright et al. 1995)

BLOCKING AGENT	distance in low-k zone ÷ distance in high-k zone	
	without crossflow	with crossflow
GELANTS		
1. low viscosity	0.10	0.10
2. high viscosity	0.32	0.99
PARTICULATES		
3. small particles	0.10	0.10
4. intermediate-sized particles	0.00	0.00
GELANT WITH PARTICLES		
5. small particles	0.10	0.10
6. intermediate-sized particles	0.01	0.01
7. large particles	0.99	0.99
8. IN SITU PRECIPITATES	0.10	0.10
FOAMS		
9. no foam forms in low-k zone	0.00	0.00
10. foam forms in both zones	0.99	0.99
11. GELANT WITH FOAM	0.99	0.99
12. DILUTE EMULSIONS	0.12	0.20

For a gelant with a water-like viscosity, the distance of penetration into the low permeability zone is 10% of that in the high permeability zone (both with and without crossflow). Increased gelant viscosity increases the relative distance of penetration into the less-permeable zone. If crossflow cannot occur between layers, the relative distance of penetration for viscous fluids is governed by the square root of the permeability ratio for the two zones. Thus, in Table 1, the value for high viscosity gelants is 0.32. If fluids can freely crossflow between zones, the distance of a viscous gelant's penetration into a low-permeability zone can be almost as great as that of an adjacent high-permeability zone. For a given distance of gelant penetration into a high permeability stratum, the minimum penetration into a less permeable zone is achieved using a gelant with water-like viscosity or mobility. Considering this conclusion, a concept has been developed in order to achieve maximal penetration of the gel, which will be discussed later.

3.2 Concentration

Al-Assi et al. 2009 conducted experiments to identify gelant concentrations that exhibited increased solution viscosity after mixing. Table 2 summarizes the range of variables studied for viscosity measurements. The polymer/aluminum weight ratio was 40:1 in all experiments. A white precipitate was observed in gelants prepared with polymer concentrations of less than 1000 ppm.

Table 2 Compositions studied by Al-Assi et al. 2009

Polymer Concentration (ppm)	Aluminum Concentration (ppm)
400	10
600	15
800	20
1000	25

The onset of gel structure formation was identified by measuring the solution viscosity using Ubbelohde #1 and Brookfield viscometers and determination of the transition pressure using the modified screen viscometer. Viscosity changes with time, observed using the Brookfield viscometer at a shear rate of 90 s^{-1} , are shown in Table 3. The 400-ppm and 600-ppm gelants were observed for thirteen days without detection of gel structure from viscosity measurements. Neither 400 ppm nor 600 ppm gelant indicated the formation of gel structure based on comparison with polymer solution properties. Similar results were observed using the Ubbelohde viscometer. Flow on this device occurs by gravity head between two fixed marks on the viscometer. Gelants were observed by periodically determining the solution viscosity of samples taken from a bottle over a period of up to six days. Viscosity data from measurements made using the Ubbelohde viscometer are shown in Table 4. No change in solution viscosity was observed in 400- and 600-ppm gel systems over a period up to six days. The 800-ppm gel system plugged the Ubbelohde viscometer after 50 hours of reaction, and the 1000-ppm gel system stopped flowing between 2.45 and 26 hours after mixing.

Table 3 Viscosity of gelants as a function of time and concentration (measured with Brookfield viscosimeter) (Al-Assi et al. 2009)

400 ppm polymer 10 ppm aluminum		600 ppm 15 ppm		800 ppm 20 ppm		1000 ppm 25 ppm	
Time (hr)	Viscosity (cp)	Time (hr)	Viscosity (cp)	Time (hr)	Viscosity (cp)	Time (hr)	Viscosity (cp)
2.47	4.29	2.33	6.62	2.53	9.25	2.70	12.5
26.7	4.91	26.28	7.03	26.07	12.7	27.5	150.4**
51	5.73	51	7.87	51	38.5*	–	–
143.8	6.23	142.7	7.28	–	–	–	–
315	5.24	315	7.28	–	–	–	–
Polymer	4.53	–	6.79	–	8.80	–	11.54

* shear rate of $45 s^{-1}$

** shear rate of $11.25 s^{-1}$

Table 4 Viscosity of gelants as a function of time and concentration (measured with Ubbelohde #1 viscosimeter) (Al-Assi et al. 2009)

400 ppm polymer 10 ppm aluminum		600 ppm 15 ppm		800 ppm 20 ppm		1000 ppm 25 ppm	
Time (hr)	Viscosity (cp)	Time (hr)	Viscosity (cp)	Time (hr)	Viscosity (cp)	Time (hr)	Viscosity (cp)
2.18	2.85	2.13	4.14	2.17	6.00	2.45	9.02
26.45	3.22	26.23	4.36	25.86	8.80	26.0	Plugged
50.8	3.51	50.22	4.49	50.50	Plugged	–	–
144.4	3.01	144.5	4.15	–	–	–	–
Polymer	2.76	–	4.14	–	5.75	–	8.07

3.3 Permeability Reduction

Strong gels fill most or all of the aqueous pore space in a porous medium and reduce the permeability of different porous rocks to approximately the same value. This behavior could be very desirable since al1 gel contacted portions of a heterogeneous reservoir could have nearly same permeability after treatment. However, for most strong gels, the final permeability is so low that flow is effectively stopped. (Unless the distance of gel penetration into the rock is very small). "Strength" of the gel is the factor that determines the permeability reduction ability of them.

A special property reported for polymers and gels is an ability to reduce permeability to water by a greater factor than that to oil or gas (Seright et al. 1995). Under the right circumstances, this disproportionate permeability reduction could shut off water channels while causing minimum damage to oil or gas productivity. This property is critical to the success of fluid-diversion treatments in production wells if zones will not be isolated during placement of the blocking agent.

Seright questions the effectiveness of the colloidal dispersion gels over polymer gels, showing that there is a controversy in the work completed before. Demonstrating the functions and applications of these two techniques, the author comes to the conclusion that CDG is not the great substitute for the polymer flooding as suggested by previous studies, especially by the CDG vendor.

Conventional gels used in in-depth diversion are anticipated to block or reduce the flow capacity of high-permeability streaks with minimum damage to less-permeable hydrocarbon-productive zones (Figure 9). This intention determines the objective, which is to minimize penetration of gelants or permeability-reducing agents into the less-permeable, oil-productive zones. Any gel or blocking agent that enters the less-permeable zones can jeopardize (or even shut off) the flow of subsequent injected fluids (e.g., water) to the productive zone and displace oil from those zones. In contrast, polymer floods and similar mobility-control methods are intended to directly displace oil from less-permeable zones (as well as improve mobility ratio and sweep in any given zone.) Consequently, a polymer solution should penetrate as deeply as possible into the less-permeable zones so that oil can be displaced from these poorly swept zones.

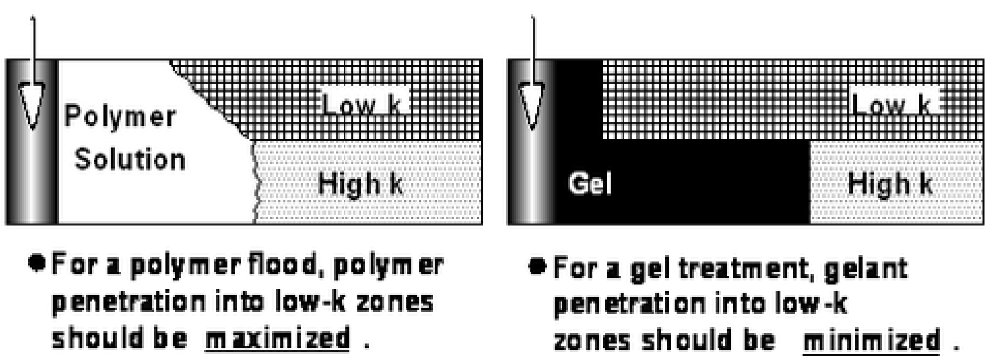

Figure 9: Distinction between a gel treatment and a polymer flood. (Seright 1991)

Seright claims that assuming a large amount of CDG would preferentially enter the high-permeability or thief zones and divert polymer or water into medium- and low-permeability zones, which, as suggested by Chang et al. 2006, violates the Darcy's law and is not technically possible. Considering this matter, application of CDG may harm the oil-productive zones. He comes to conclusion that, even though application of CDG can be successful in some cases, this treatment should not be considered as a substitute for polymer flooding.

Our research is intended to study only performance of the deep diverting gels. Technical or practical application will not be heavily considered. Some runs will even include cases that are not possible with today's technology. Even though this study is concentrated purely on performance evaluation, the controversial arguments will be considered on the simulation. Modeling and results of the simulation are shown in the following chapters.

3.4 Thermal Activation

As mentioned before, although colloidal dispersion gels are a good tool for fluid diversion and sweep improvement, there is a controversy about their behavior in porous media. This led researchers to develop a type of chemical that would flow through this media as easy as water, meanwhile increasing the production.

An industry consortium consisting of BP, ChevronTexaco and Nalco, conducted a joint research to develop the project called Bright Water. The goal of this project was to develop a time-delayed, highly expandable particulate material that would be able to penetrate deep into porous media and improve the sweep efficiency of a water flood. This could be achieved by injecting a low viscosity material, which subsequently triggered to form a highly viscous blocking phase.

In water flooding projects, there is usually a thermal front formed between the injection and the production wells, due to low temperature of the injected water into oil reservoirs. The novel polymeric microparticles, in which the microparticle conformation is constrained by reversible (labile) internal crosslinks has been reported (Chang et al 2002.). These microparticles are able to advance through the pore space and be thermally triggered when they reach the thermal front deep inside the reservoir. The microparticle properties of the constrained microparticle, such as particle size distribution and density, are designed to allow efficient propagation through the pore structure of hydrocarbon reservoir matrix rock, such as sandstone. On heating the rock to reservoir temperature and/or at a predetermined pH, the reversible (labile) internal crosslinks start to break, allowing the particle to expand by absorbing the injection fluid (usually water).

The ability of the particle to expand from its size at the point of injection depends only on the presence of conditions that induce the breaking of the labile crosslinker. It does not depend on the nature of the carrier fluid or the salinity of the reservoir water. These particles can propagate through the porous structure of the reservoir without using a designated fluid or a fluid with a salinity higher than the reservoir fluid.

As they reach the thermal front, particles are triggered with the heat, expand and create the blocking phase (Figure 10). The expanded particle is engineered to have a particle size distribution and physical characteristics - for example, particle rheology -

which allow it to impede the flow of injected fluid in the pore structure. In doing so, the expanded particle is capable of diverting chase fluid into less thoroughly swept zones of the reservoir.

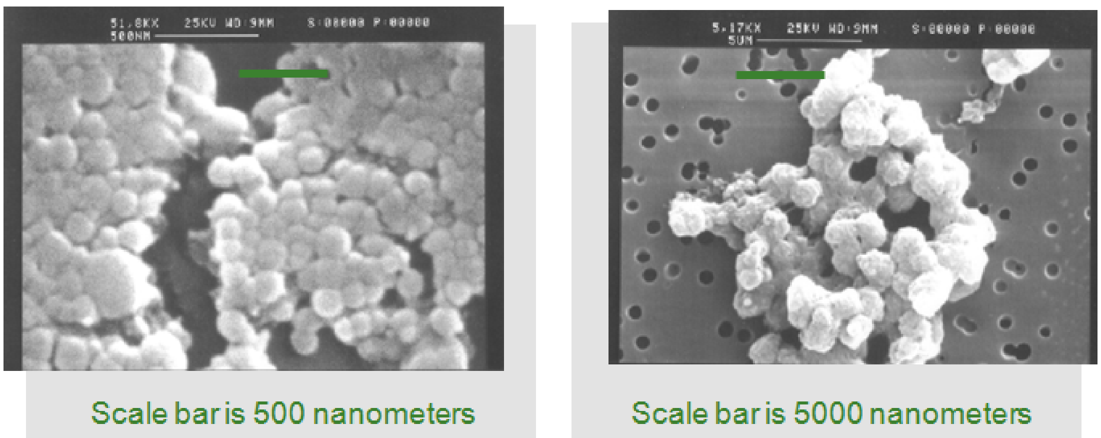

Figure 10: Particles before and after expansion.

The rheology and expanded size of the particle can be designed to suit the reservoir target, for example by suitable selection of the backbone monomers ratio of the polymer or of the degree of reversible (labile) and irreversible crosslinking introduced during manufacture. The following two figures (Figure 11 and 12) illustrate this concept.

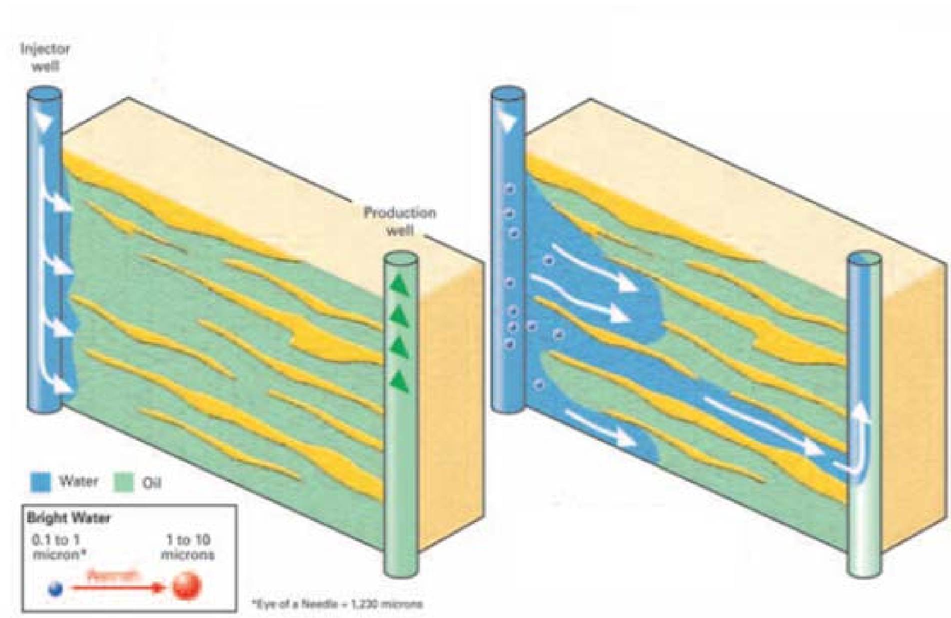

Figure 11: a) Water Injection, b) Injection of DDG particles

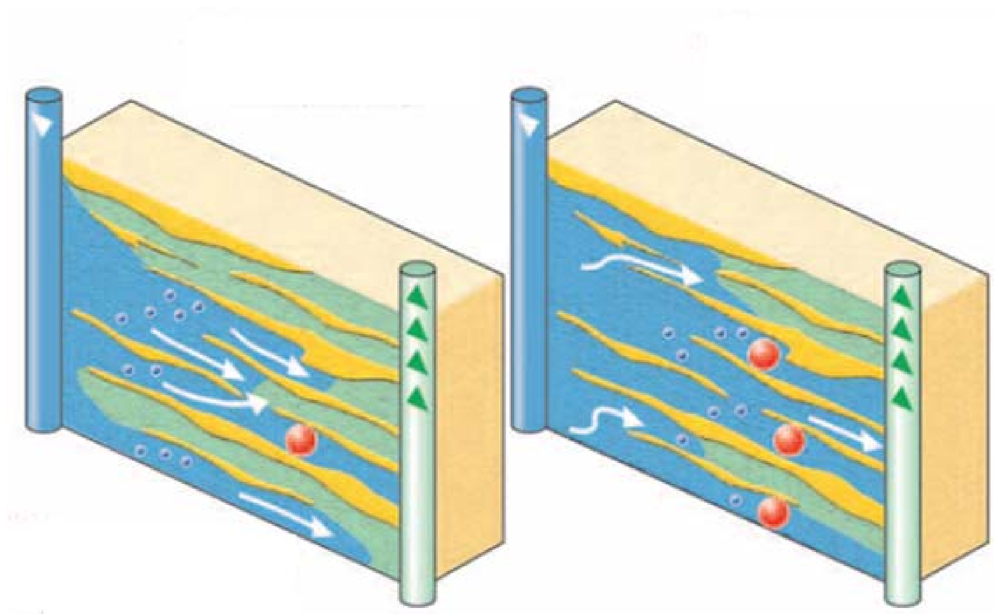

Figure 12: Thief zones are plugged by DDG (Smith, 2007)

IV RESERVOIR MODEL DESCRIPTION

4.1 Simulator

As previously described, it was planned to model the behavior of water flooding, polymer flooding and in-depth diverting gel treatment. Schlumberger’s Eclipse 100 Black Oil simulation software (Eclipse) was used in conjunction with the thermal and polymer option. There are many popular simulators with the ability to run models of this research using detailed chemistry. Computer Modeling Groups (CMG) STARS and the University of Texas Chemical Compositional Simulator (UTCHEM) are some of these simulators. Schlumberger’s Eclipse 100 differs from these simulators with not modeling the detailed chemistry and, instead, considering the important features of the process on a full field basis (Schlumberger, 2007, 2008). Later stages of research proved the deep chemical approach for modeling the main purpose of this research was not necessary.

4.2 General Reservoir Description

4.2.1 Assumptions

5-spot well spacing on water flooding projects is one of the most commonly observed configurations. It had been decided to build a quarter of a 5-spot well spacing, with heterogeneity in vertical direction, in order to demonstrate breakthrough of water within high permeability zones. Some assumptions were made in order to build this model, as listed below:

- Since the purpose of our research is to model and observe the behavior of different enhanced production methods, there was no real data used in this modeling. The field is fictitious and all data will be approximated to specific values of parameters.
- The quarter of 5-spot well spacing where single production and single injection well is assumed to be located on the corners of the square.
- Only water and oil will be present on the model. No gas effect is considered in this study.
- There is no aquifer support on the production. The only water influence is from the injection well.

4.2.2 Well Configuration

The following is the well configuration for the quarter of the 5-spot pattern. All wells were vertical and located in the center of the 60 foot net pay zone. Well parameters and an aerial view of the reservoir can be seen in the Table 5 and Figure 13 accordingly.

Table 5 Well information

	Location (X, Y, Z_1-Z_2)	Well Radius, ft	Completion Depth, ft	Liquid Rate, bbl/d
Production "P"	(44,1,1-15)	0.27	8030	500
Injection "I"	(1, 44, 1-15)	0.27	8030	500

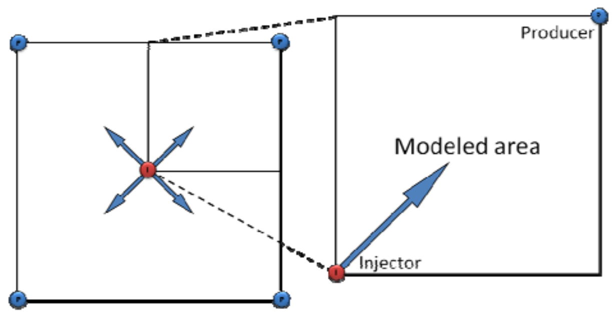

Figure 13: Areal view of the model and well location

4.2.3 Reservoir Properties

As mentioned previously, this reservoir is fictitious and most of the parameters are based on assumptions that mimic realistic data. The following tables (Table 6, 7, 8) demonstrate inputs for the models.

Table 6 Model inputs

Model		
Start Date	1/1/2000	
Grid Blocks in X	44	
Grid Blocks in Y	44	
Grid Blocks in Z	15	
Total Area	10	Ac
X length	660	ft
Y length	660	ft
Z length	60	ft
Depth	8000	ft
Porosity	0.25	
Normal Perm X	100	mD
High Perm X	1200	mD
Normal Perm Z	10	mD
High Perm Z	100	mD
Plug Perm X	40	mD
Plug Perm Z	10	mD
WOC	15000	ft

Table 7 Fluid properties

Properties		
Water Formation Volume Factor	1	rb/stb
Water Compressibility	3.03E-06	
Water Viscosity	0.7	cp
Water Specific Gravity	1.07	
Oil Formation Volume Factor	1.01	rb/stb
Oil Viscosity	2	cp
Oil API	34.2	
Rock Compressibility	5.00E-06	

Table 8 Wellbore properties and production parameters

Production parameters		
Production Well Location	*44, 1, 1-15*	
Injection Well Location	*1, 44, 1-15*	
Economic Limit	0.95 WCT	
Control Parameter (P)	*Liquid rate*	500
Control Parameter (I)	*Water rate*	500

4.3 Model Development

The model development section will include major steps taken during the simulation process to reach the final model and will demonstrate reasons and methods for the actions taken.

4.3.1 Layer Change

The first configured model consisted of four layers. The top three had the same properties (basically making them grid refinement of thick geological layer) with low/normal permeability, and the bottom layer had extremely high permeability, creating pathway for injected water to production well. The following diagram (Figure 14) demonstrates the placement of layers.

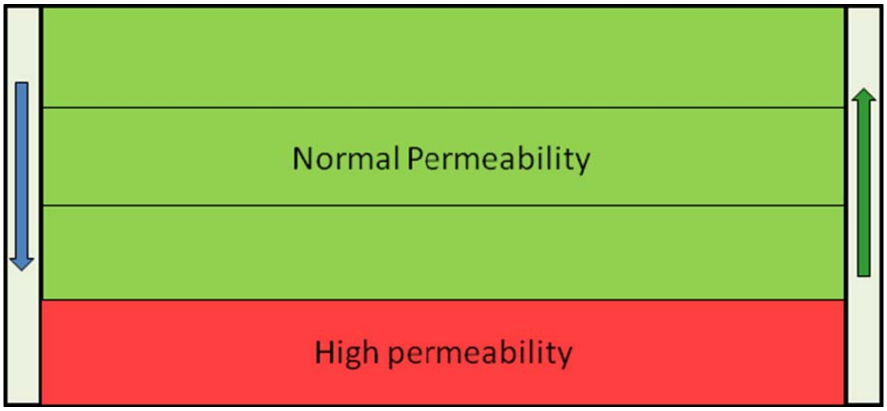

Figure 14: Layer configuration of early mode

Although breakthrough from a high permeability zone to a production well was observed in this model, change in the layers' configuration has been decided. Three geological layers (with high perm zone on the middle) have been proposed and each of these layers has five grid layers. This option was supposed to lead to more precise observation of water flow through high permeability zone and the effect of gravity on the sweeping process. The figure (Figure 15) below demonstrates the final configuration of the model.

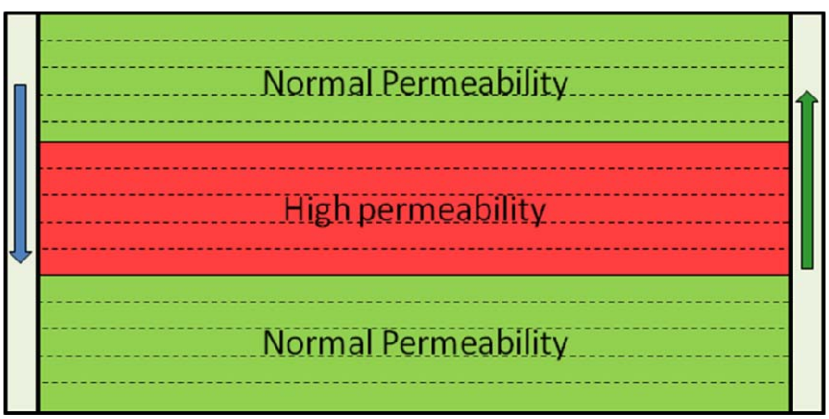

Figure 15: Modified layer structure of the model

4.3.2 Grid Refinement

In the early stages of research, increasing grid size from the wellbore towards the middle of the reservoir had been selected to model the reservoir. (Figure 16) This configuration of grids was supposed to result in more precise observation of near-wellbore flow behavior. Although this model was working well for the above mentioned purpose, it had some drawbacks as well:

- Creating very small gridblocks around wellbores would result in a large number of gridblocks. This would mean that simulation would require high computer processing speed and long run time and could lead to complications in later stages of research on more complex models.
- It was hard to evenly distribute the deep penetrating gels on the uneven gridblocks.
- Since one of the main purposes of the research was to observe the performance of deep penetrating gels, regions near the wellbore were not the only regions necessary for study. It is necessary, instead, to observe the performance on every point of a reservoir evenly.

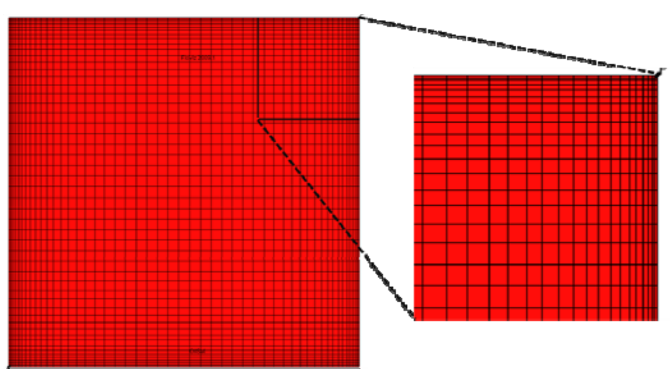

Figure 16: Model with different grid sizes

Due to reasons stated above, gridblocks of the same size throughout the reservoir model has been applied at the later stage. Sensitivities to a number of grids in X and Y directions (20x20, 44x44, 110x110) were performed, and results led to the conclusion that using 44x44 (Figure 17) was the best configuration in terms of precision vs. performance.

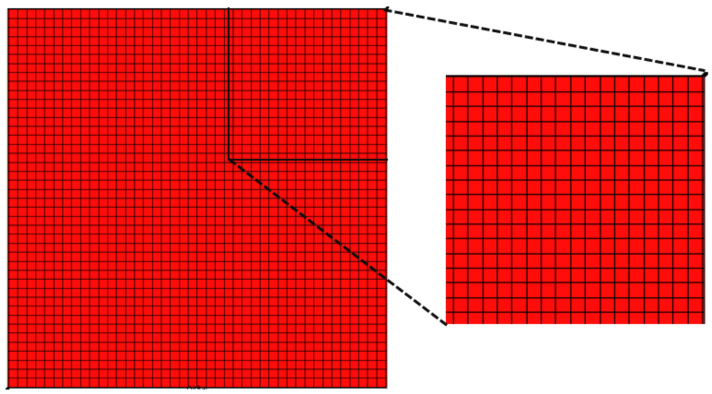

Figure 17: Model with the same grid sizes

The only size difference was on the side grid blocks. Lengths of these blocks were decreased in order to make corner blocks area as close to that of wellbore as possible (Figure 18). This has minimized the error related to extra (not on actual drainage area of the wellbore on this model) area beyond the wellbore. This area is shown yellow on the following Figure 19.

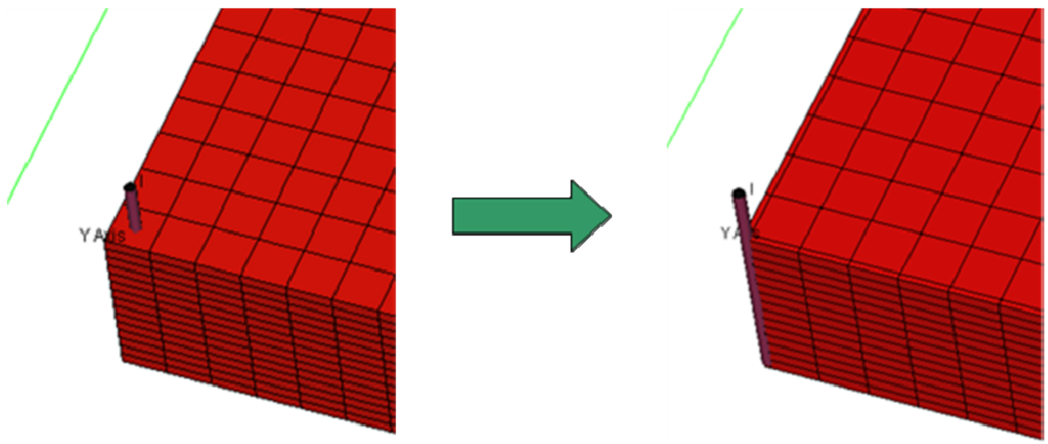

Figure 18: View of the modified gridblocks on 3D model

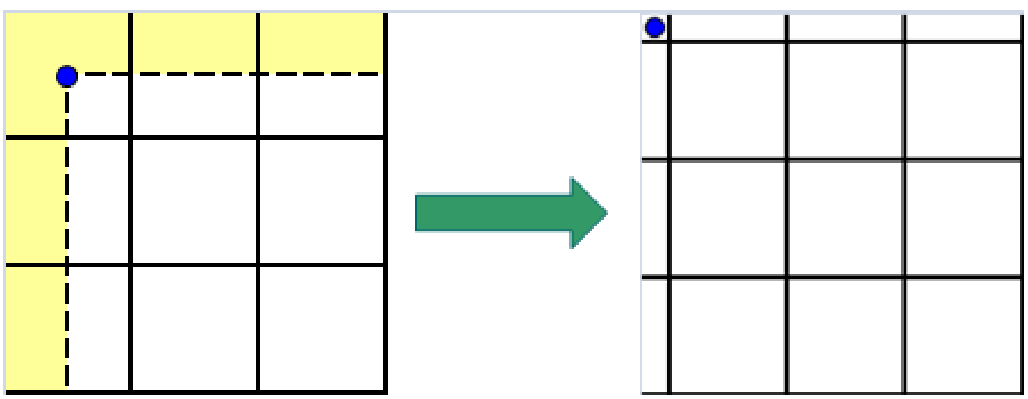

Figure 19: Modification of side and corner gridblocks

4.3.3 Thermal Model

As it was explained on theory part of this report, gel particles move freely throughout the pores and create the gel plug when they reach the thermal front. Thermal option has been added to Eclipse 100 models, in order to be able to locate the thermal front at specific time of run, since it was required for modeling the deep diversion gels.

The minimum thermal properties required by temperature option are the specific heat capacity of the rock and the fluids present in the reservoir. The rock specific heat is entered as a volume specific heat, tabulated against temperature. The fluid specific heats are mass specific heats, again tabulated against temperature.

In ECLIPSE 100 an energy conservation equation is solved at the end of each converged time step, and the grid block temperatures are updated. The new temperatures are then used to calculate the oil and water viscosities for the subsequent time step. Both rock and fluids in a grid block are assumed to be at the same temperature.

Table 9 Assumed thermal parameters

Thermal Parameters		
Reservoir Temperature	*210*	F
Injected Water Temperature	*70*	F
Specific Heat of Rock	*25*	btu/rft^{3}F
Oil Specific Heat	*0.5*	btu/lbm F
Water Specific Heat	*0.95*	btu/lbm F

4.4 Polymer Flooding

The function of the polymer injection during water flooding is to reduce the mobility ratio of the injected water. This decrease results in a more favorable fractional flow curve for the injected water, leading to a more efficient sweep pattern and reduced viscous fingering. The mobility decrease of the injected water resulting from the addition of polymer is due to two effects. First, the rock permeability to water is reduced after the polymer solution passes through the rock. Second, the viscosity of the polymer solution is higher than that of pure water (increase of the polymer concentration in the water results in increase of the viscosity of the polymer solution). Both effects lead to the reduction of water mobility value while that for the oil is almost unaltered.

The ECLIPSE model allows you to investigate the effect of varying brine concentrations on the efficiency of the polymer flood. It should be noted that the effect of temperature variations on the behavior of the polymer solution is currently ignored.

When a polymer solution is injected into the reservoir some of the long chain molecules constituting the polymer are adsorbed onto the rock surfaces. Mechanical entrapment of some of the large molecules at the entrance to small pore throats may also occur and account for an apparent loss of polymer from the invading solution. Experimentally, the reservoir rock material is believed to retain a specific capacity of polymer. The main effects of polymer loss occur at the leading edges of the polymer slug where a stripped water bank is created and the slug width is gradually reduced in time. Some desorption effects can occur as the trailing edge of the slug passes but these effects are usually small compared with the adsorption losses.

A further effect caused by the adsorption and entrapment processes is a reduction in the relative permeability of the polymer solution. The reduction results from an interaction between the aqueous solution and the polymer retained by the rock material. For modeling purposes it will be assumed that the reduction in permeability to the polymer solution is proportional to the quantity of polymer lost to the rock material. The permeability of the rock to water is thus permanently reduced after the passage of a polymer slug compared to its value before the passage. Experimentally, it is found that only a very small change occurs to the hydrocarbon relative permeability and the Eclipse model assumes that the change is negligible.

In core flooding experiments, it is often observed that injected polymer slugs break through to producers earlier than tracer slugs (for example, NaCl). The polymer fluid velocity is higher than that of the tracer fluid within the porous medium and is due to the fact that only a fraction of the total pore space is available to the polymer fluid. As the inaccessible pore space to the polymer fluid increases, the effective polymer velocity through the rock increases and leads to a faster breakthrough of polymer. ECLIPSE assumes that the dead pore space is constant for each rock type and does not exceed the corresponding irreducible saturation.

The rheology of polymer solutions is not simple. At low flow rates the viscosity of the solution is approximately constant and depends only on the concentration of polymer in the solution. At higher flow rates the solution viscosity reduces in a reversible (elastic) manner. At even higher velocities the large polymer molecules begin to break up, and the viscosity reduction becomes irreversible (plastic). The effects tend to be greatest in the vicinity of injection wells where the fluid velocity is greatest, and so is the shear rate.

The flow of the polymer solution through the porous medium is assumed to have no influence on the flow of the hydrocarbon phases. The standard black- oil equations are therefore used to describe the hydrocarbon phases in the model.

Modification is required to the standard water equation and additional equations are needed to describe the flow of polymer and brine within the finite difference grid. The water, polymer and brine equations used in the model are as follows by order:

$$\frac{d}{dt}\left(\frac{VS_w}{B_r B_w}\right) = \sum\left[\frac{Tk_{rw}}{B_w \mu_{w\,eff} R_k}(\delta P_w - \rho_w g D_z\right] + Q_w$$

$$\frac{d}{dt}\left(\frac{VS_w C_p}{B_r B_w}\right) + \frac{d}{dt}\left(V\rho_r C_a \frac{1-\phi}{\phi}\right) = \sum\left[\frac{Tk_{rw} C_p}{B_w \mu_{w\,eff} R_k}(\delta P_w - \rho_w g D_z\right] + Q_w C_p$$

$$\frac{d}{dt}\left(\frac{VS_w C_n}{B_r B_w}\right) = \sum\left[\frac{Tk_{rw} C_n}{B_w \mu_{w\,eff} R_k}(\delta P_w - \rho_w g D_z\right] + Q_w C_n$$

4.5 Deep Diversion Gels

In-depth conformance control gels are relatively new technology which is in stage of development. There is still controversy about settlement and performance of these gels. Since there is no solid proven technique for deep conformance control as water flooding or polymer flooding, there is no model available on commercial simulators for this treatment. This was the main challenge of this study and required a creative approach than simply building a straightforward model on the software.

We have studied the thermally activated gel types as an example of deep diverting gels. Water like properties of this gel was an advantage in modeling in terms of neglecting the effect of the particle flow before blockage. Using this advantage we assumed that there is no significant sweep change while flow of the early particles into the reservoir till they reach the thermal front. The main consideration for the modeling was the final effect which is the reduction of the permeability of the thief zone and diversion of fluid.

In order to model the permeability reduction at some point (treatment time) of the run, the new model with permeability change had to be created after some time of initial run. It was assumed that the gel treatment has been applied at 85% field water cut. On the water flooding (abbreviated as WF) file timestep consistent to this limit (step 65, 1796 days, 12/01/2004) has been noted. Since the activator for the particles is the heat, the permeability reduction is supposed to occur at the thermal front which was determined using thermal option as described previously. Following figure illustrates the reservoir temperature profile of high permeability streak (increasing from blue to red, 70 - 210°F) and the placement of the blocking agent (reduced permeability, shown in yellow) according to thermal front.

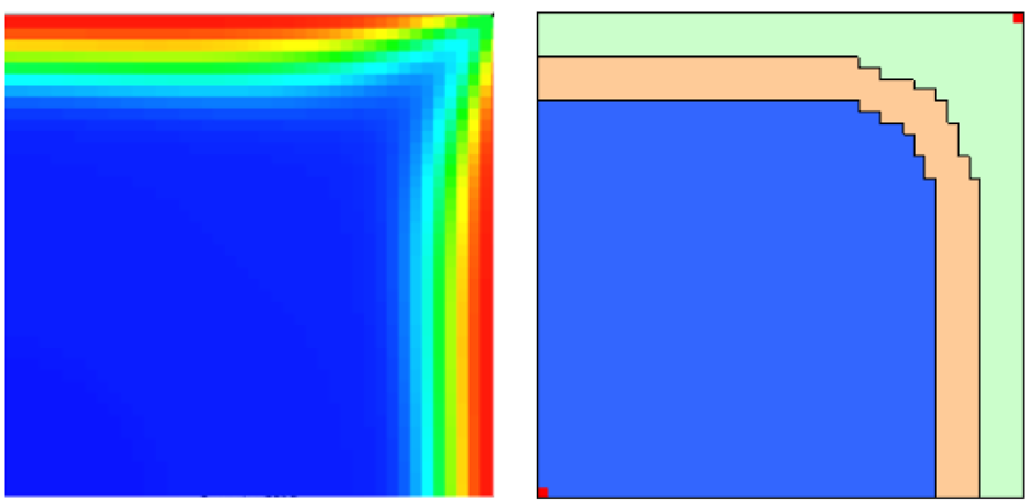

Figure 20: Actual reservoir temperature (left) and modeled blocking agent (right)

Temperature distribution of the middle layer with high permeability rock is shown on previous figure. As expected, temperature front of the top and bottom layers is located behind that of the middle layer due to slower advance of water. Injected particles flow into low permeability zones and create the block there as well. Since the distance from injection well to thermal front is the watered out zone, it is not expected that the plugs on low permeability reservoirs will have much of an impact on the production. Due to this, it was assumed to neglect these plugs on the base case and consider them in another sensitivity run to observe the difference.

At the end of each timestep results are saved as a data file and RESTART function of the ECLIPSE on the new model reads the time dependent parameters such as fluid saturation from the linked (original) model's data file for each timestep. This makes available making changes on the non-time dependent parameters, in this case permeability, on the second model. New model has been created with reduced permeability on the gridblocks as shown on Figure 20 and RESTART function to restore the rest of the parameters from the last timestep. Overall picture of the permeability distribution of the final model is shown on Figure 21.

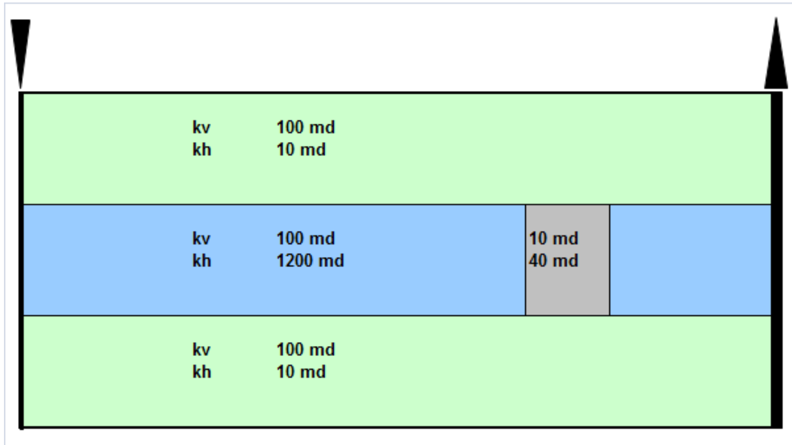

Figure 21: Permeability distribution view from side.

V DISCUSSION OF RESULTS

This section will include the results of previously discussed models. In this section we will discuss and compare the results from the water flooding, polymer flooding and the deep diversion gel models.

5.1 Water Flooding

This model was the base case where the excessive water production due to high permeability streaks occurs. Figure 22 depicts the problem by illustrating the oil saturation after throughout the field after about 13 month of production. One can notice the rapid advancement of the water on middle layer and breakthrough on production well (low oil saturation) from the same layer, which corresponds to the stated problem. This plot is in full agreement with the production rates in terms of time. Figures 23 - 26 show the plots of the main parameters demonstrating the production performance of the water flooding project.

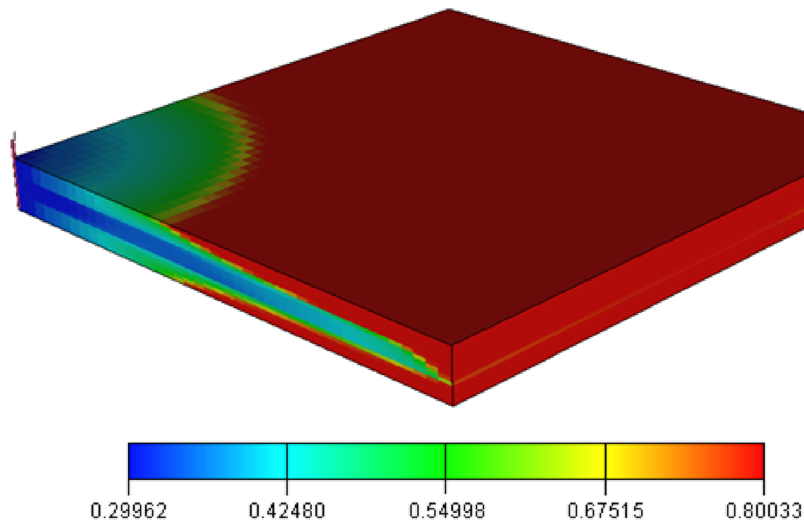

Figure 22: Oil saturation after 13 months of production

Water breakthrough has occurred in fairly early stage of the production. Slow decrease of the bottomhole pressure (Figure 23) of the production well till the breakthrough is the prove of how effective this model could have been if the high permeability streak wouldn't present and shows the importance of solving this matter in the reservoir.

As it was discussed on the inputs part of the report, control parameters for wells were liquid volume. For injection well the limit was 500 bbl/d water injection and for production well limit was the same number, but for total liquid (sum produced oil and water). Due to this balance in the reservoir, decrease in reservoir pressure is slight. (Figure 23).

Water and oil production show the reverse behavior both in production rate and cumulative production (Figures 24, 25). Rapid increase in water production and decrease in oil production after breakthrough can be observed. This leads to sharp increase of cumulative water production curve and decreased slope of cumulative oil production curve.

Balance in injected and produced liquids also leads to the shape of water production rate and watercut to be exactly the same, since in this case watercut is the ratio of production rate to total produced liquid, which is constant. (Figure 26)

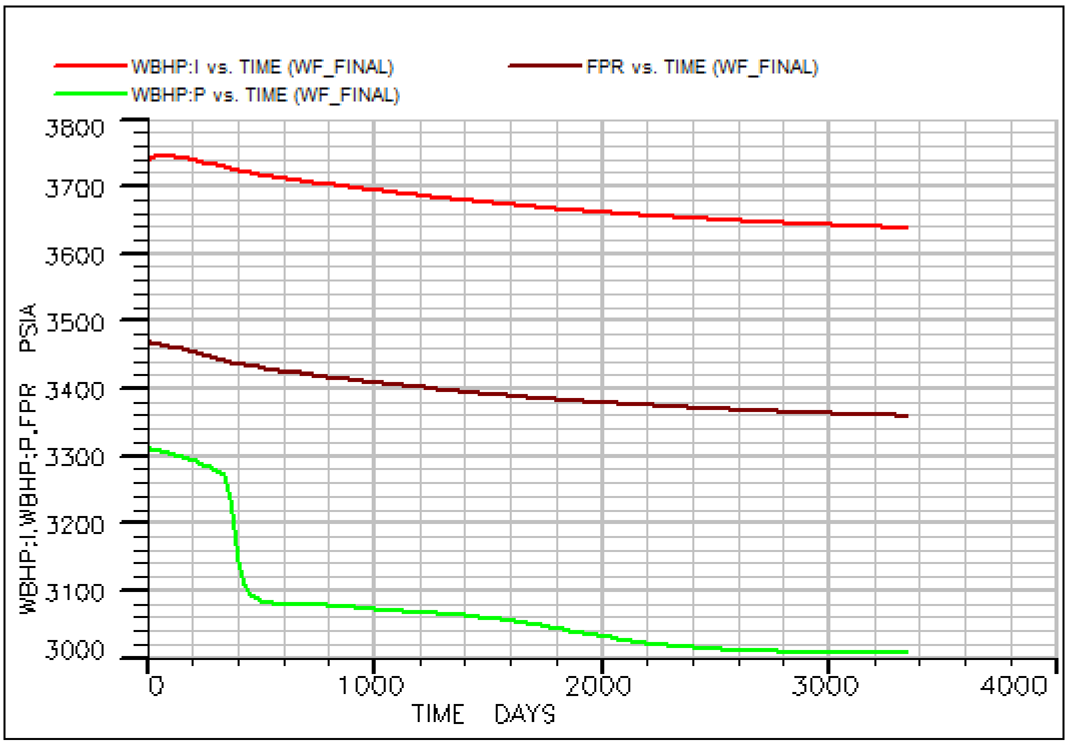

Figure 23: Reservoir and bottomhole pressures

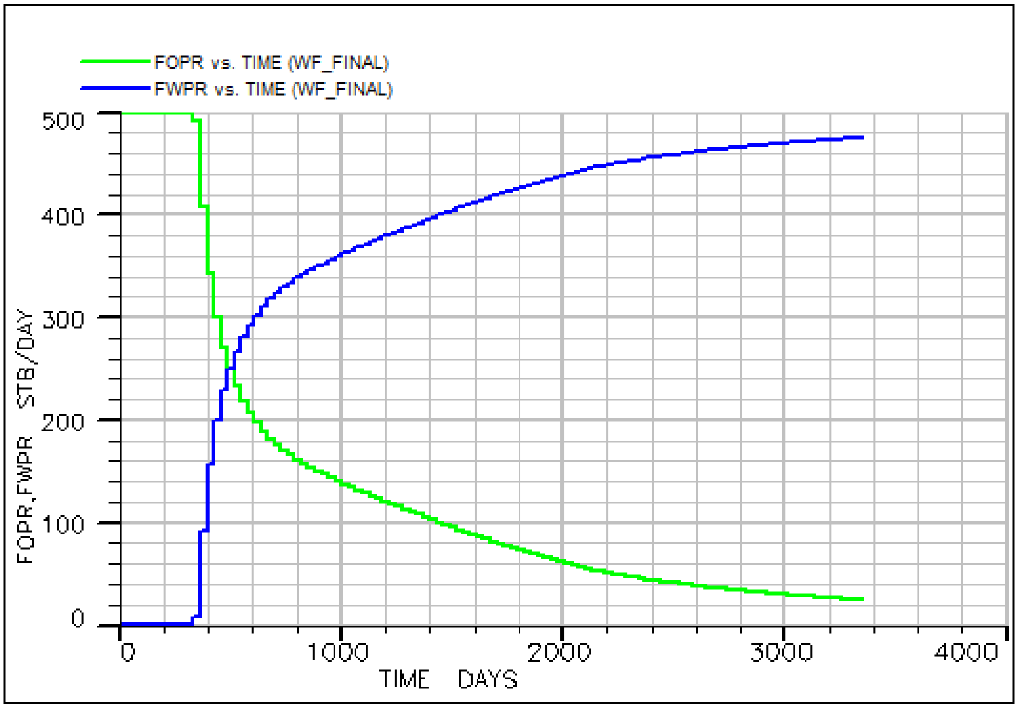

Figure 24: Oil and water production rates

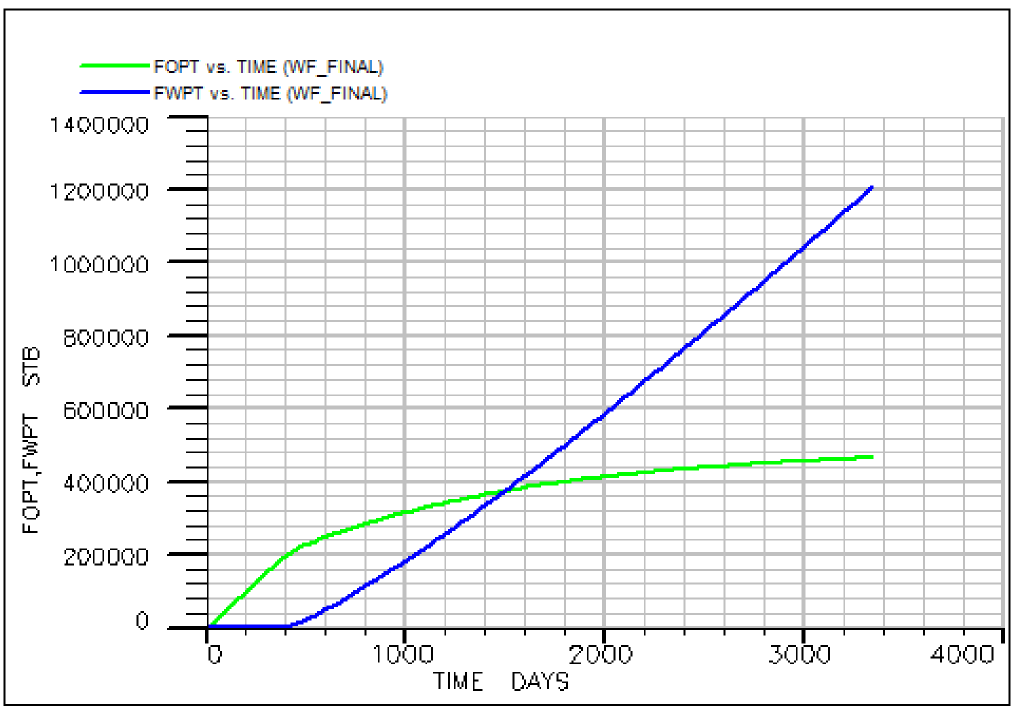

Figure 25: Cumulative oil and water production

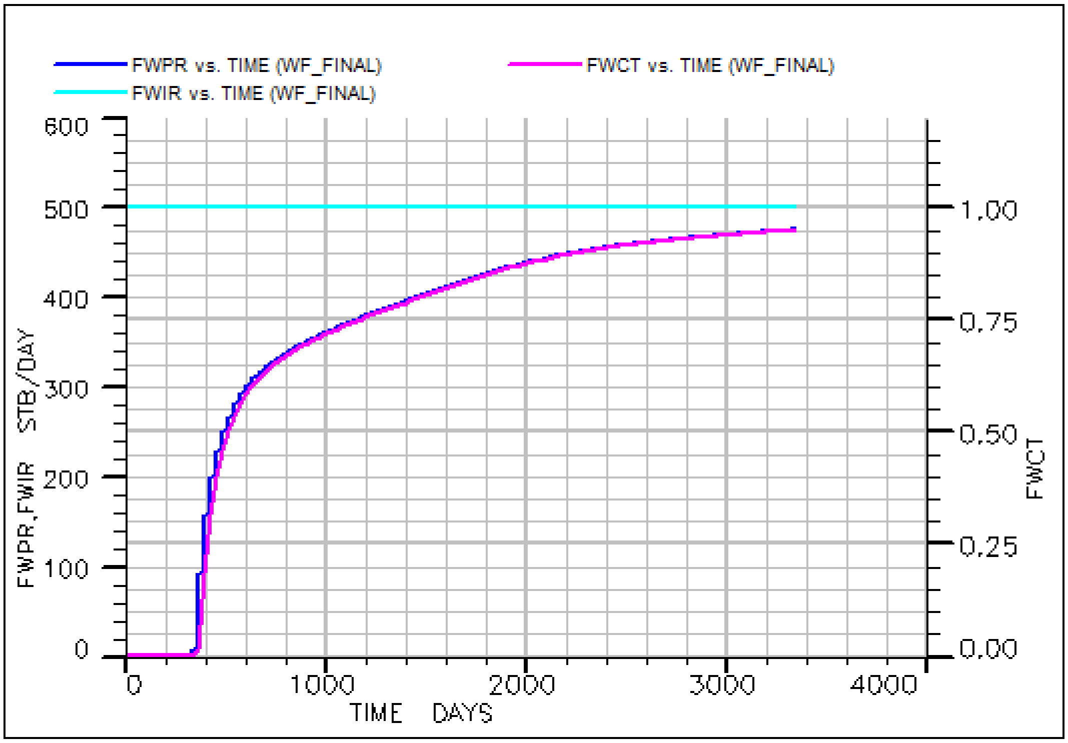

Figure 26: Water injection and production rates, and watercut

5.2 Squeeze Cementing

In order to model this treatment basically the offending zone has been isolated. Squeeze cementing has been applied at the same time step as in-depth conformance control gel for comparison purposes. This method was not the main objective of the research, but it has been modeled in order to compare chemical and mechanical treatments.

Isolating the watered zone in reservoirs with crossflow leads to water flowing through high permeability zone to be diverted into low permeability zones just near the production well. This results in slight increase of oil sweep from that zone for very short time, but after that period oil production from the low permeability zone may actually be harmed, since water occupies (Figure 27) some part of the thickness of low permeability layer which produces oil.

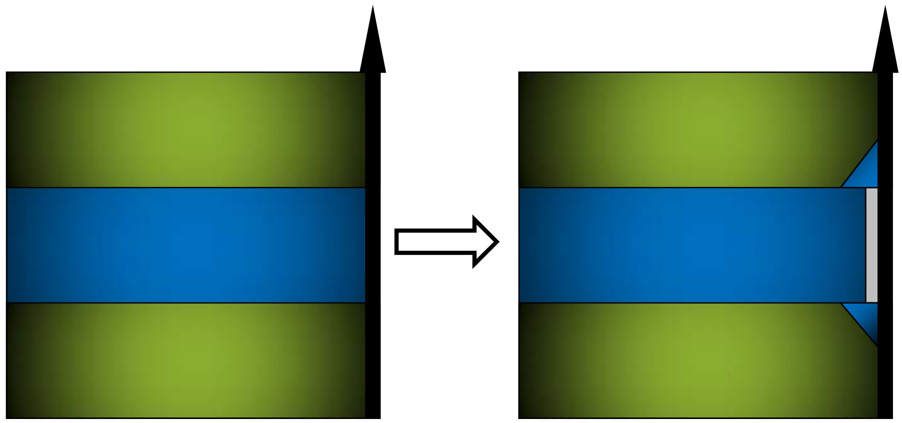

Figure 27: Water bypassing cemented region

Middle layer has been shut on both injection and production well in order to model the cementing job on this problem. There was no significant incremental oil production from this treatment. Slight increase in oil production was observed right after the application of treatment. This was due to the diversion of water from the isolated zone and as soon as the water finds a way around the isolation to flow, same water and oil production rate re-established (Figure 27). This increase of oil rate is for very short period of time and has very minor effect on the total production (Figures 28 - 31).

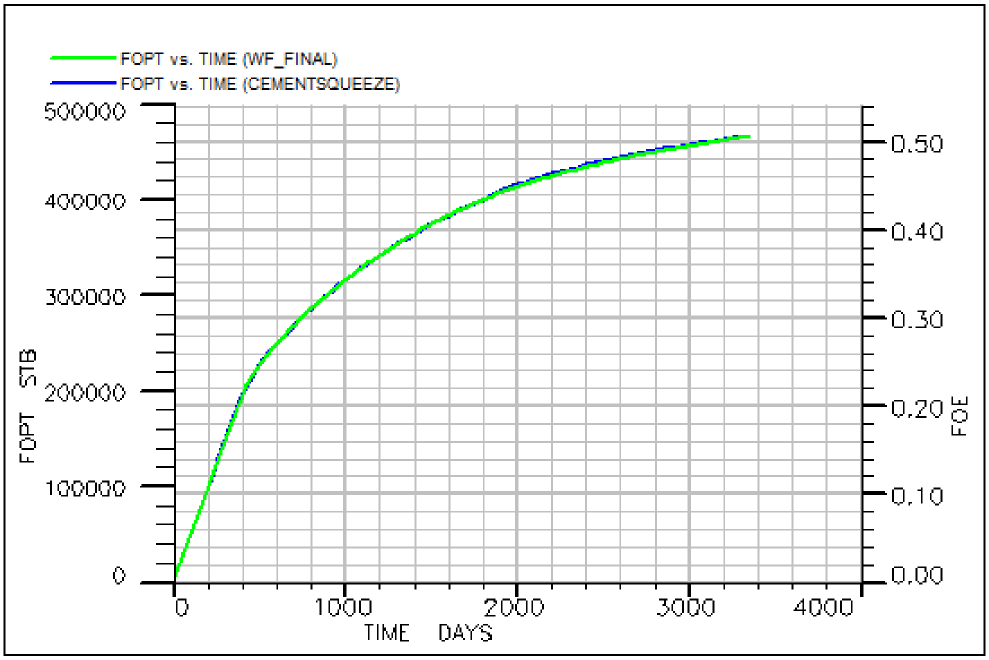

Figure 28: Cumulative oil production and oil recovery factor

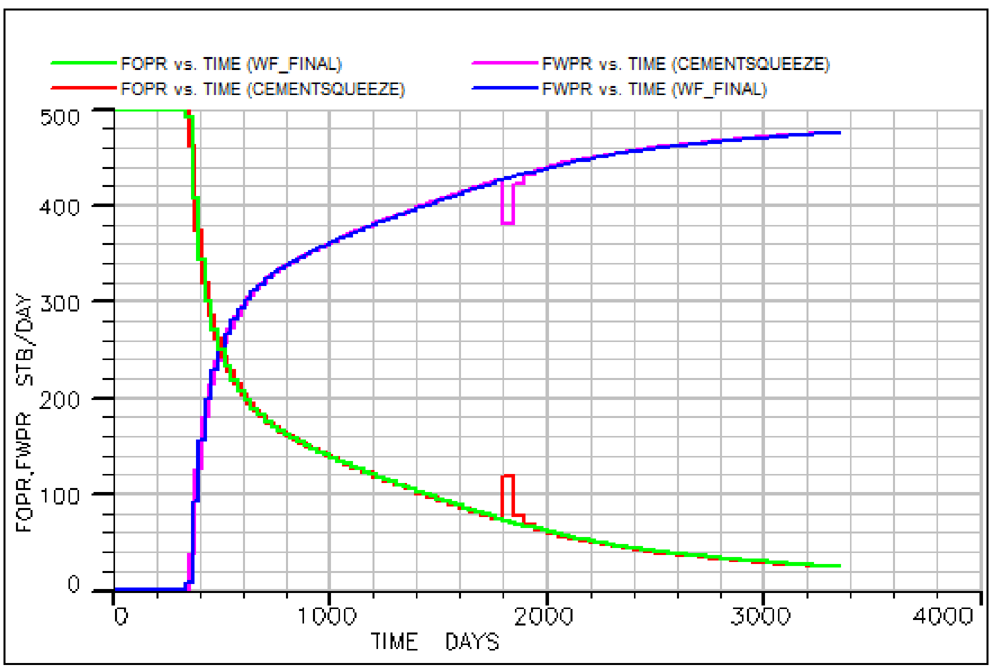

Figure 29: Water and oil production rates

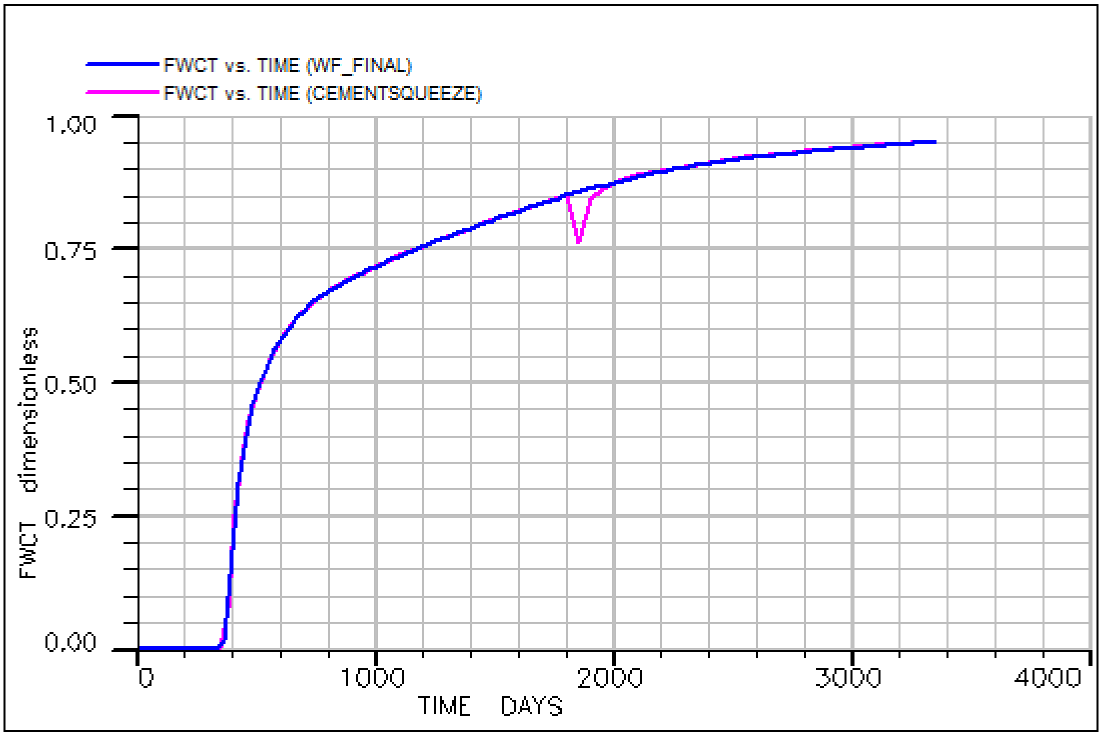

Figure 30: Watercut

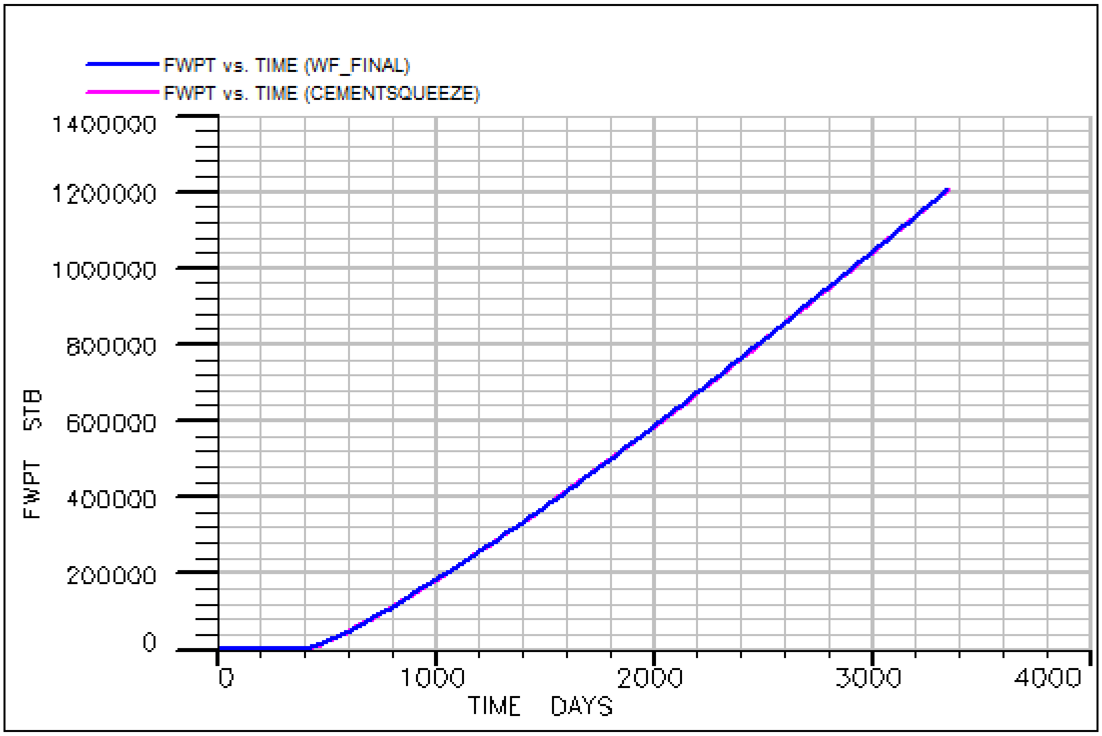

Figure 31: Cumulative water production

5.3 Polymer Flooding

Polymer has been injected to the reservoir with high permeability reservoir in order to increase the sweep efficiency. 1000 ppm (0.35 lb/stb) polymer concentration has been assumed for this model.

Polymer flooding has been started at the same time step as gel treatment for comparison purposes. As soon as breakthrough of polymer occurred the injection has been reconverted to water injection only (Figure 32).

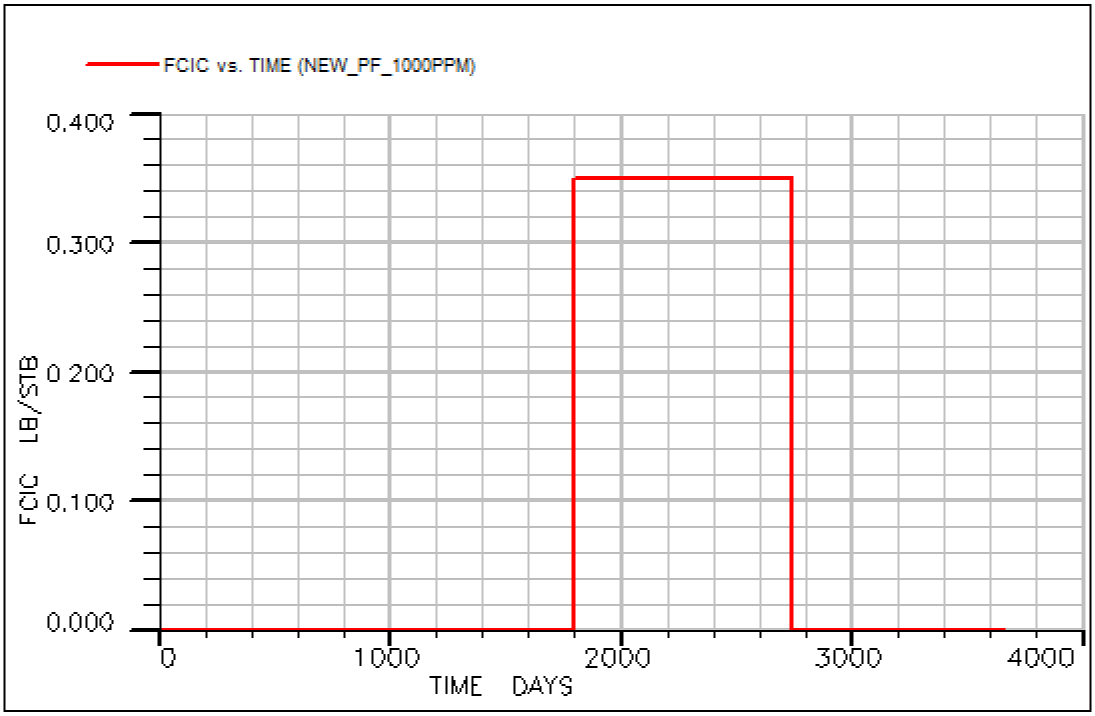

Figure 32: Injected polymer concentration

Results (Figures 33 - 36) showed that as expected, this treatment has better oil recovery compared to water flooding. Polymer injection results in even displacement of oil and slow movement of the polymer - oil front, which increases the production time.

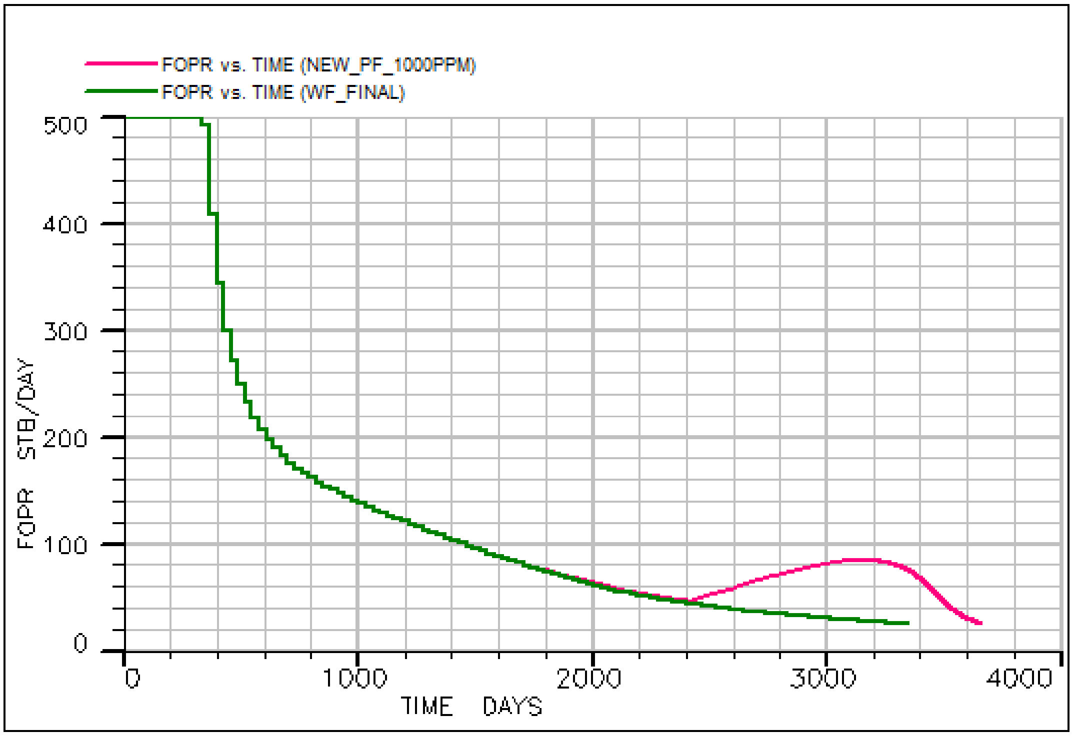

Figure 33: Oil production rate of polymer and water flooding

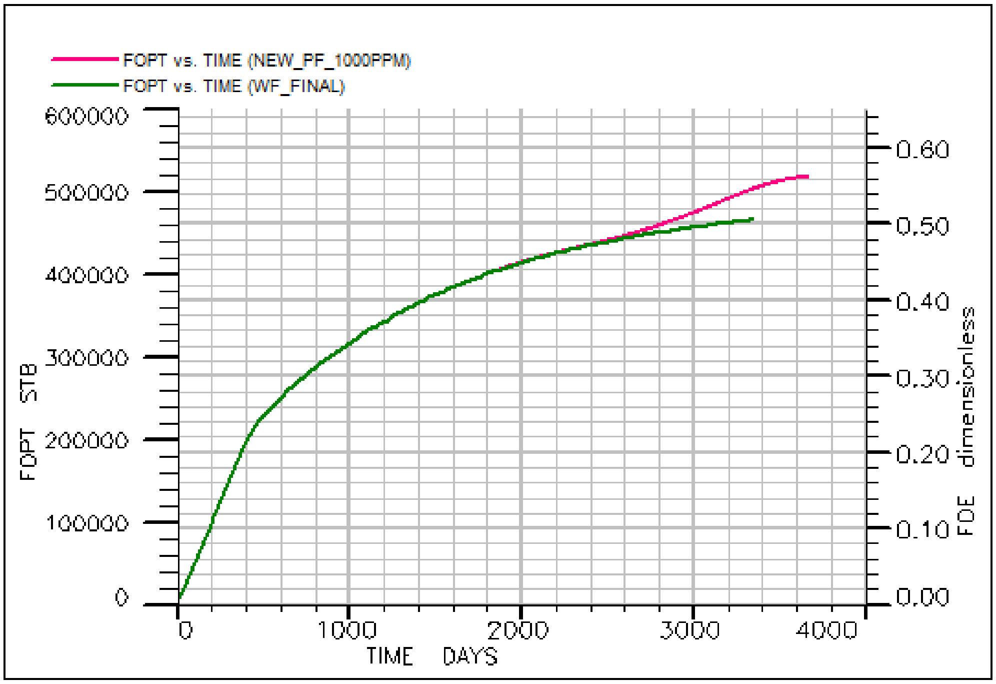

Figure 34: Cumulative oil production and total recovery (PF and WF)

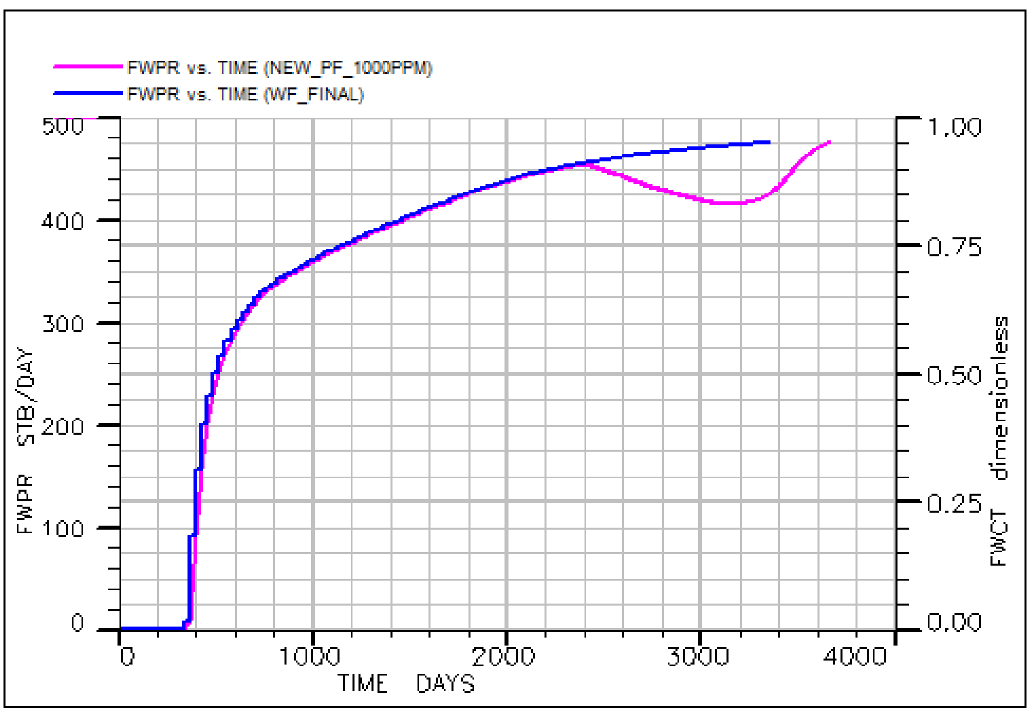

Figure 35: Water production rate (PF and WF)

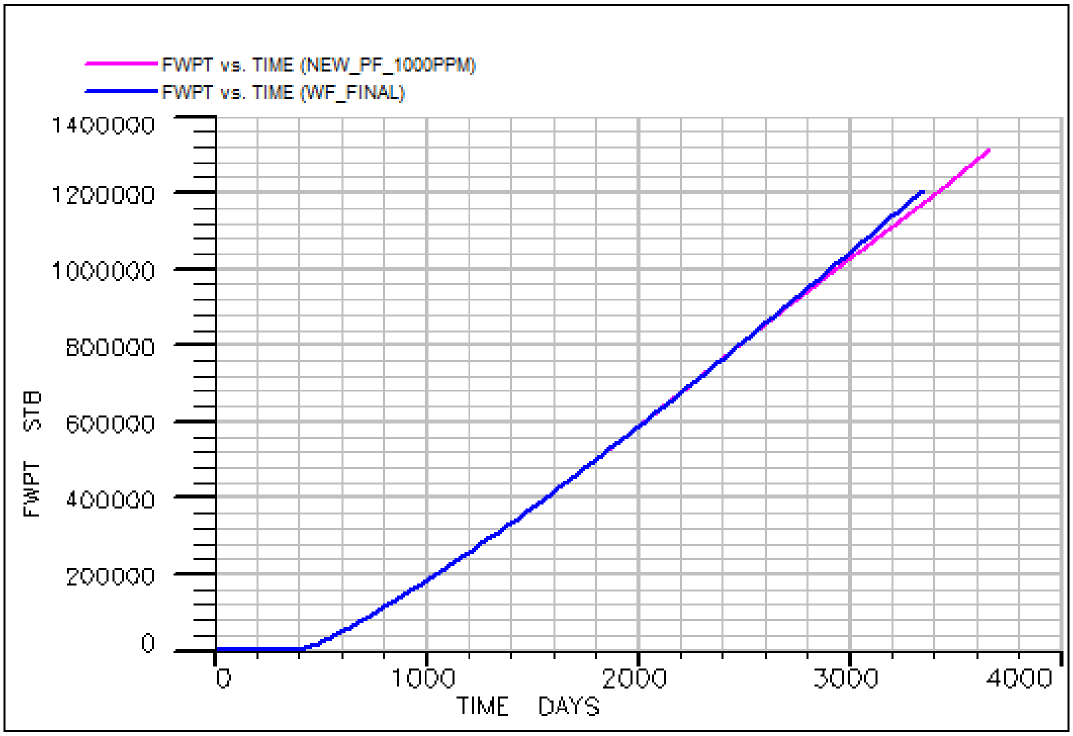

Figure 36: Cumulative water production (PF and WF)

5.4 DDG Model Selection

Two cases have been investigated in order to select the "base" case for the deep diversion gel model. First the blockage of the low permeability zones has been considered (Figure 37), whereas on second case this consideration was ignored. It was expected that since the thermal front of low permeability zones is far away from that of the middle layer, blocking of these zones should not dramatically affect the production. Permeability of layers and plugs on first case are shown on the following figure.

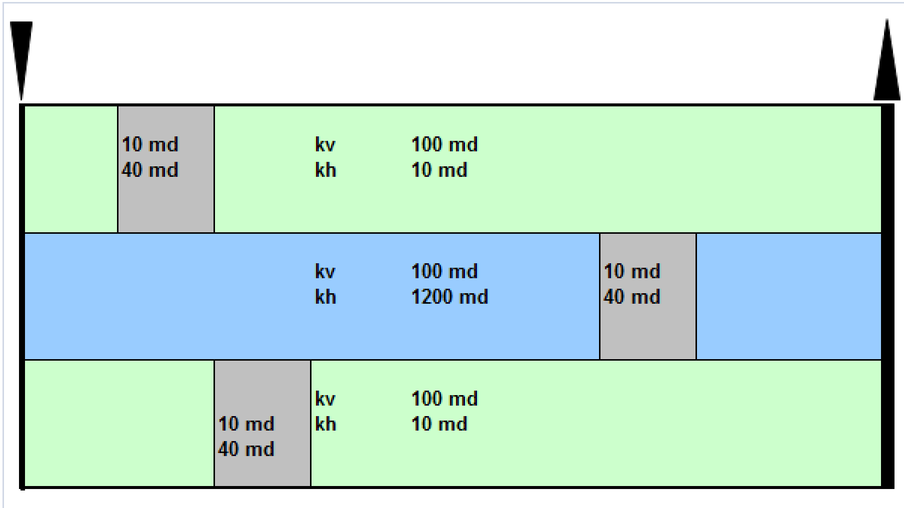

Figure 37: Zone and plug permeability

Results of simulation runs are in agreement with expectations and are shown on following figures. Cumulative oil production and recovery factor plots (Figure 38) demonstrate that the increase of total oil production on the case with top and bottom layer plugs would be around 0.3%. Although this percentage is not a large impact to overall recovery factor, considerable amount of oil can be achieved from 0.3% of large fields, thus it cannot be neglected. Bearing this "small error" in mind we decided to analyze less complicated model and consider it as an assumption. Even less significant differences can be observed on the cumulative water production curve (Figure 39). Differences between water and oil production rates, and water cut of two cases can be observed on figures 40 and 41 relatively.

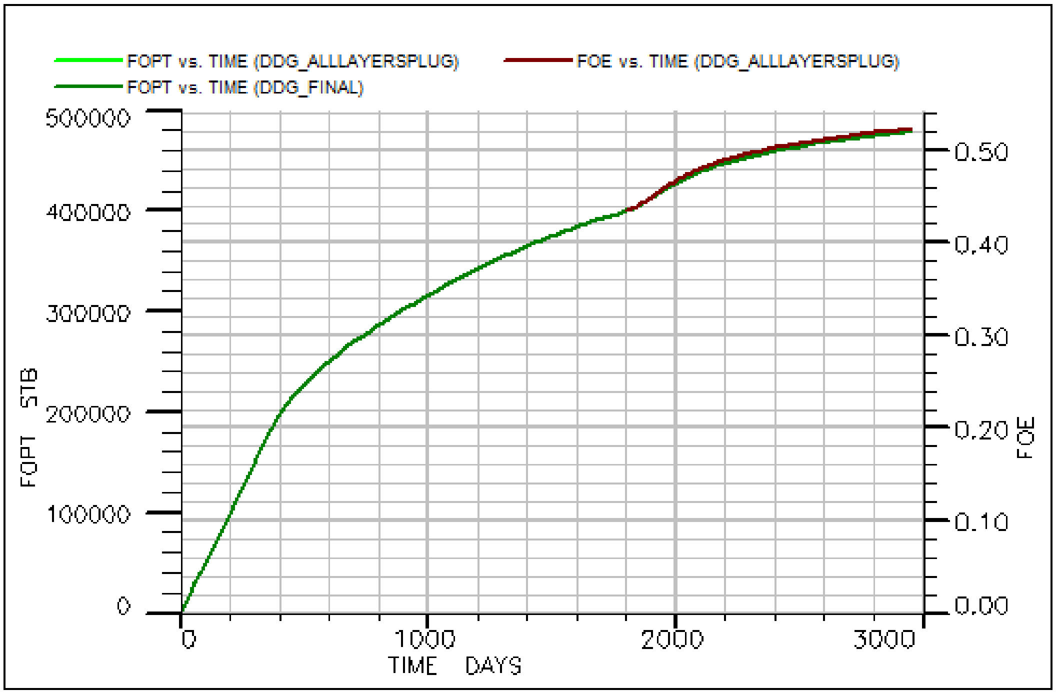

Figure 38: Cumulative oil production and oil recovery factor comparison of DDG models

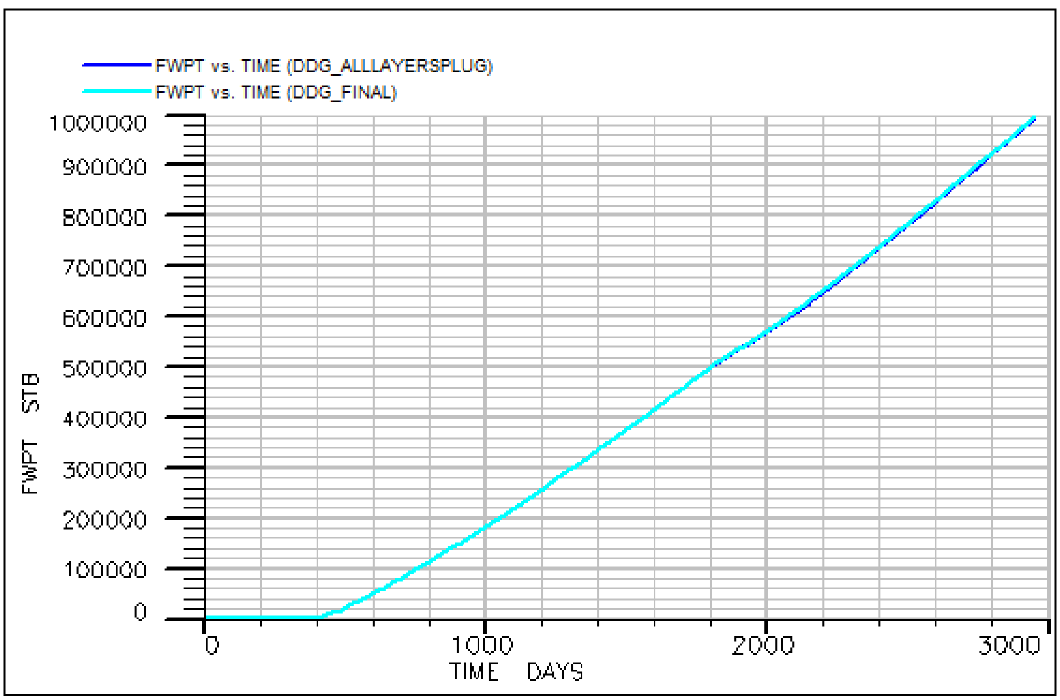

Figure 39: Cumulative water production comparison of DDG models

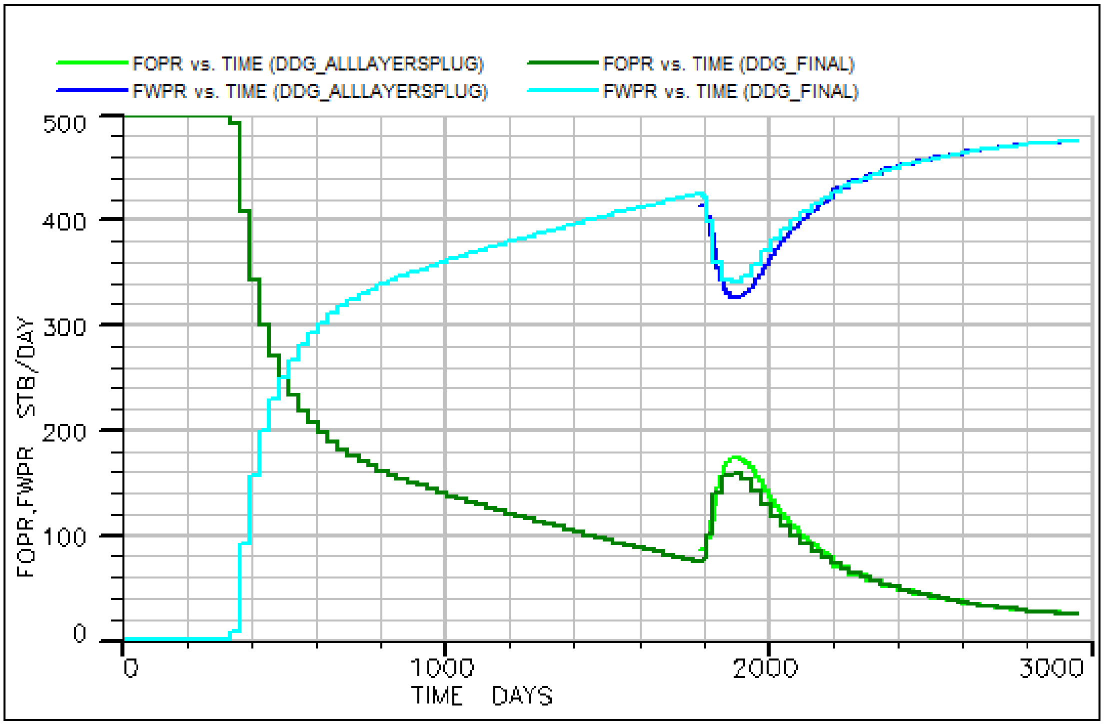

Figure 40: Water and Oil production rates comparison of DDG models

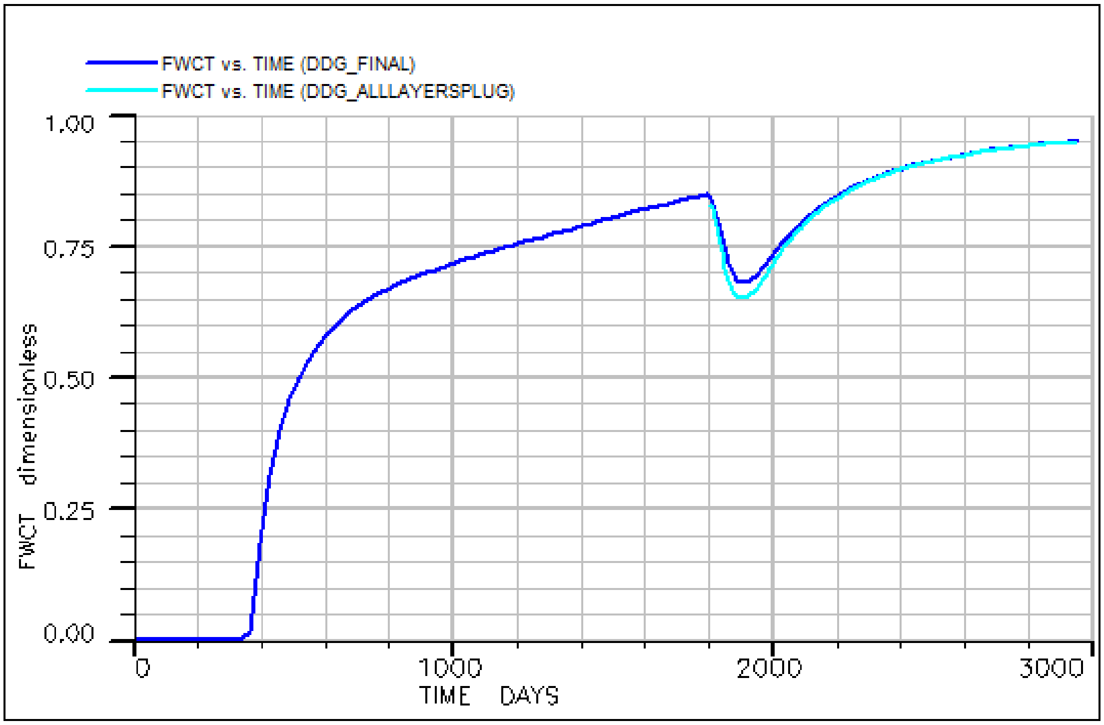

Figure 41: Watercut comparison of DDG models

Considering these results, it has been decided to neglect placement of the blocking agent on the low permeability zones and model a plug only on the middle (high permeability) layer on the base case.

5.5 Deep Diversion Gel

Model with ignored blockage on low permeability layers have been selected as a base case for comparison with other methods and also for sensitivity runs. Results taken from this run have been plotted along with water flooding and polymer flooding results in order to investigate their performance (Figure 42 - 45).

Application of deep diversion gels has added about 1.5-2% of incremental oil to water flooding, but this amount was less than the increase observed in polymer flooding.

Unlike polymer flooding, deep diversion gels have decreased production time, which can be a good deal for the operators interested in shorter production of reserves.

In depth blockage results in diversion of water into less permeable zone and increases the cumulative oil. Since water bypasses both the oil and plug when it sweeps large enough area for pathway, water is not diverted all the way to the top of layer. This leads to limited increase of sweep.

Overall, in depth blockage shortened production while increasing the overall recovery in our study, while polymer flooding increases the recovery more significantly with extended production time. Each case has its own advantage and drawbacks, so both of them can be the best treatment depending on problem and company's interests.

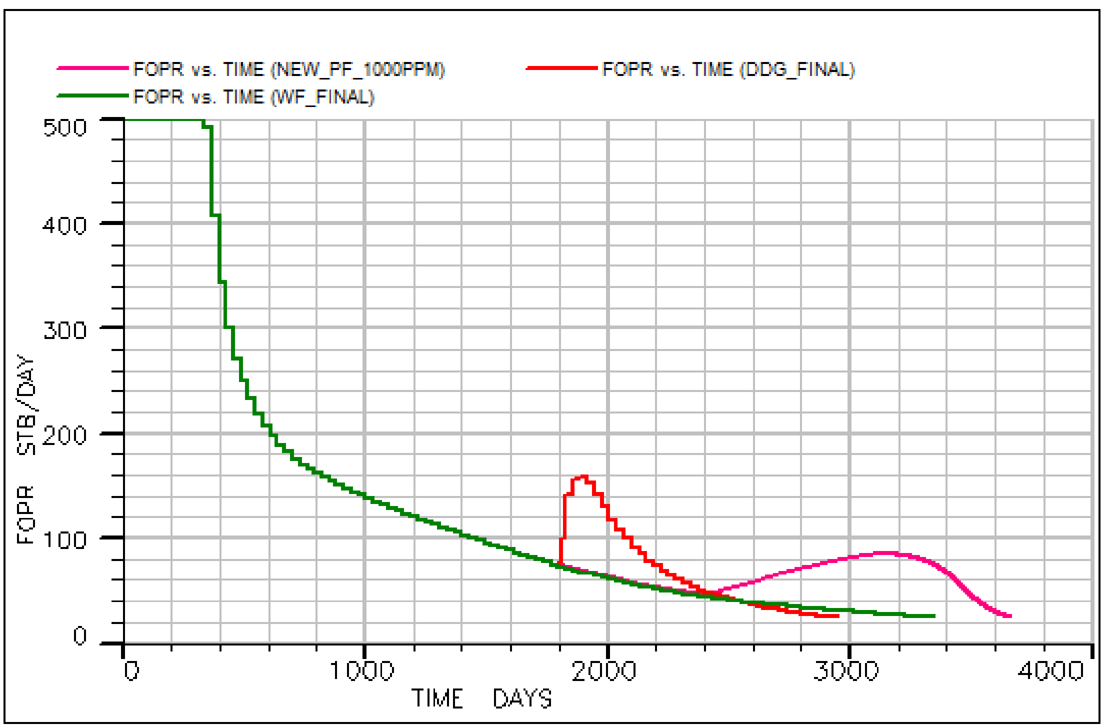

Figure 42: Oil production rate of all three treatments

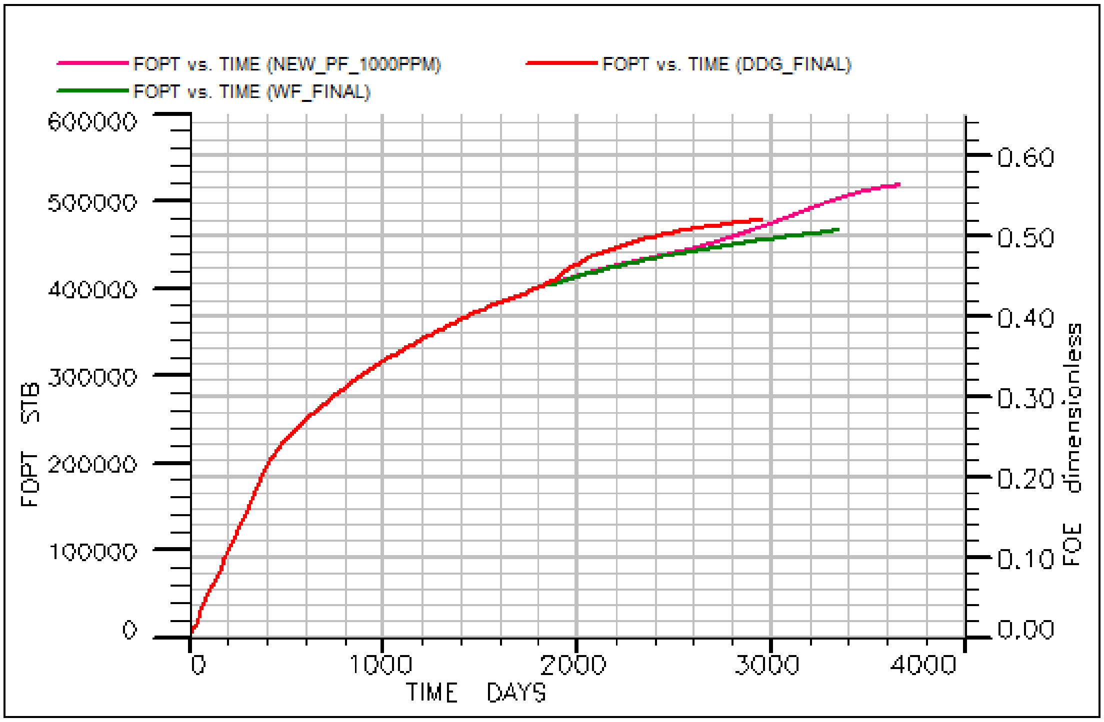

Figure 43: Cumulative oil and recovery factor of all three treatments

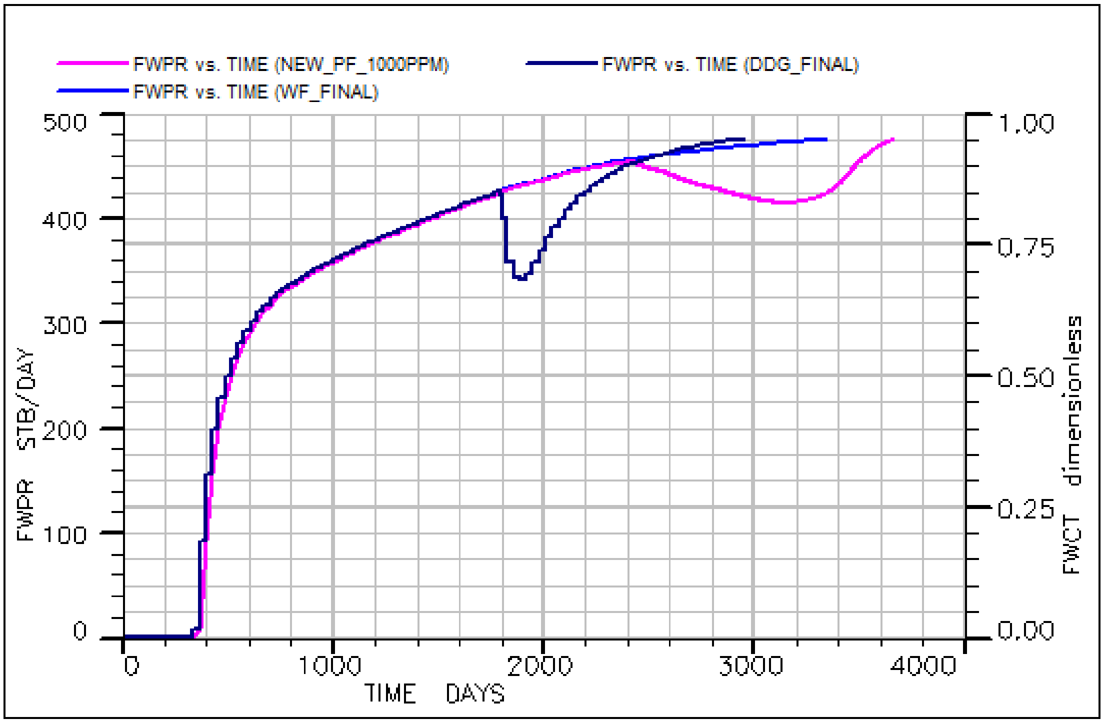

Figure 44: Water production rate and watercut of all three treatments

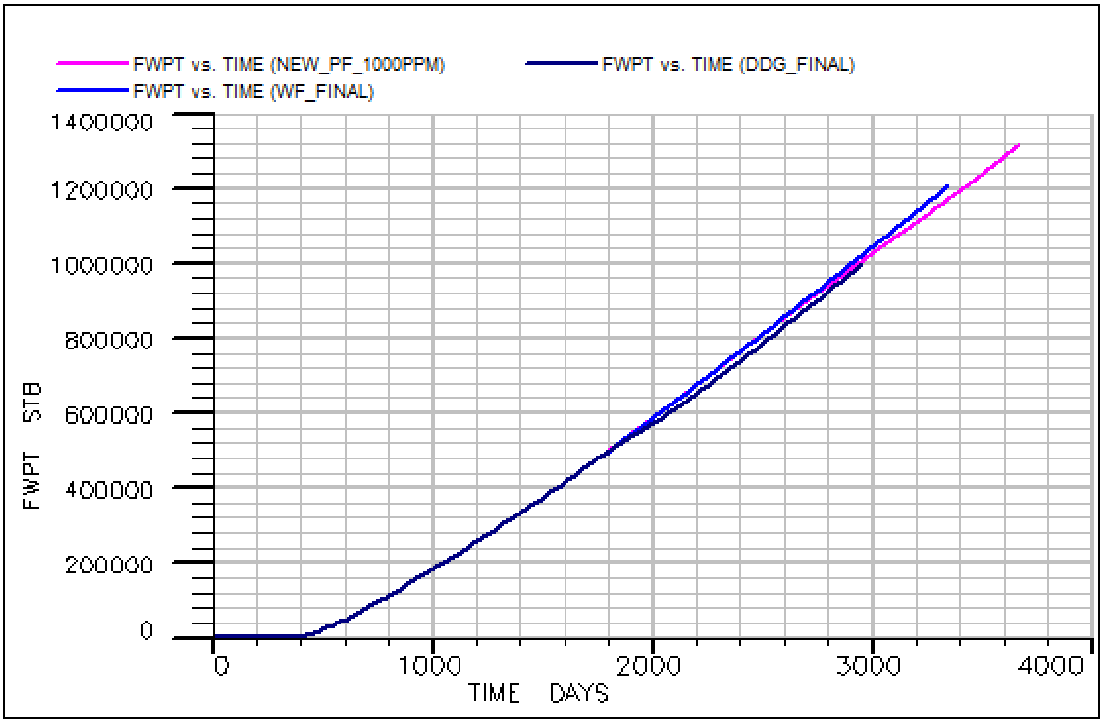

Figure 45: Cumulative water production of all three treatments

VI SENSITIVITY RUNS

Sensitivity runs were performed in order to improve the performance of the treatment. Plug shape, placement, and size were main parameters evaluated on sensitivity runs. Conclusions have been made according to the results of those runs.

6.1 Treatment Time

Base conformance control treatment model has been modified assuming early application of treatment. Change in time (i.e. assumed watercut) yields to different location and size of the formed plug. As thermal front advances with time, formation of the block occurs further from injection well (closer to production well). Apart from base case, two models have been built (Figure 46) in order to show the effect of timing on the production performance of this treatment. The treatment assumed to be applied at 21st time step (160 days) on first case and at 49th time step (720 days) on second case. Plug size increases as temperature front advances towards production well, since size of the transition region of thermal front is different on different stages of the production.

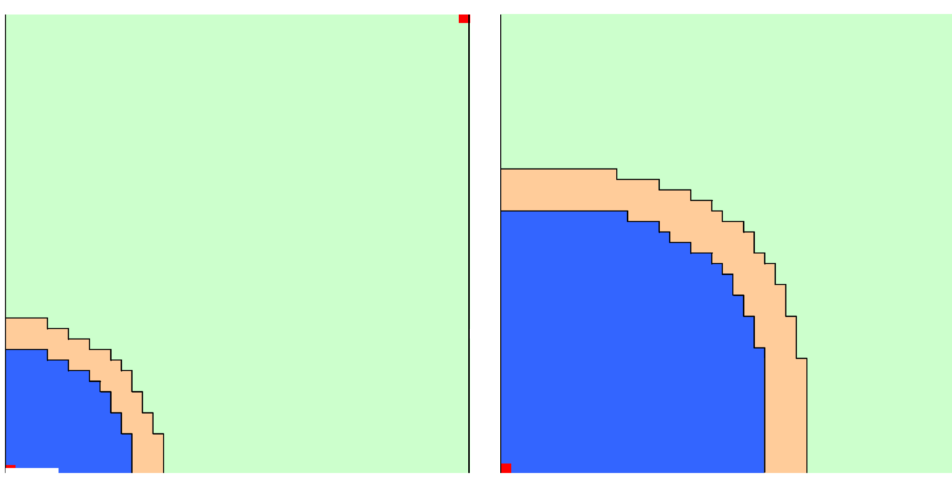

Figure 46: Location and size of the plug at two different application times

Apart from the mentioned models, base case has also been included to comparison. As it was expected, results demonstrated that the early placement of the plug yields in earlier increase of oil and decrease of water production rates (Figure 47 and 48). This change results in the opposite behavior of these rates after some time. One can read from following plots that the difference between cumulative oil productions of base case (DDG_final) and the case with closest distance from injection well to the plug (DDG_closedist) is about 1% of overall production (Figure 49). Moreover, the production from base case finishes 200 days earlier. This means that the smaller the plug is, the longer it will take to produce the reservoir (the less it helps to production). Due to this extended time, there is extra amount of water produced which is also a matter of concern (Figure 50). Considering all these results, we came to the conclusion that the plug must be placed as far from injection well as technically possible without blocking the flow to the production well.

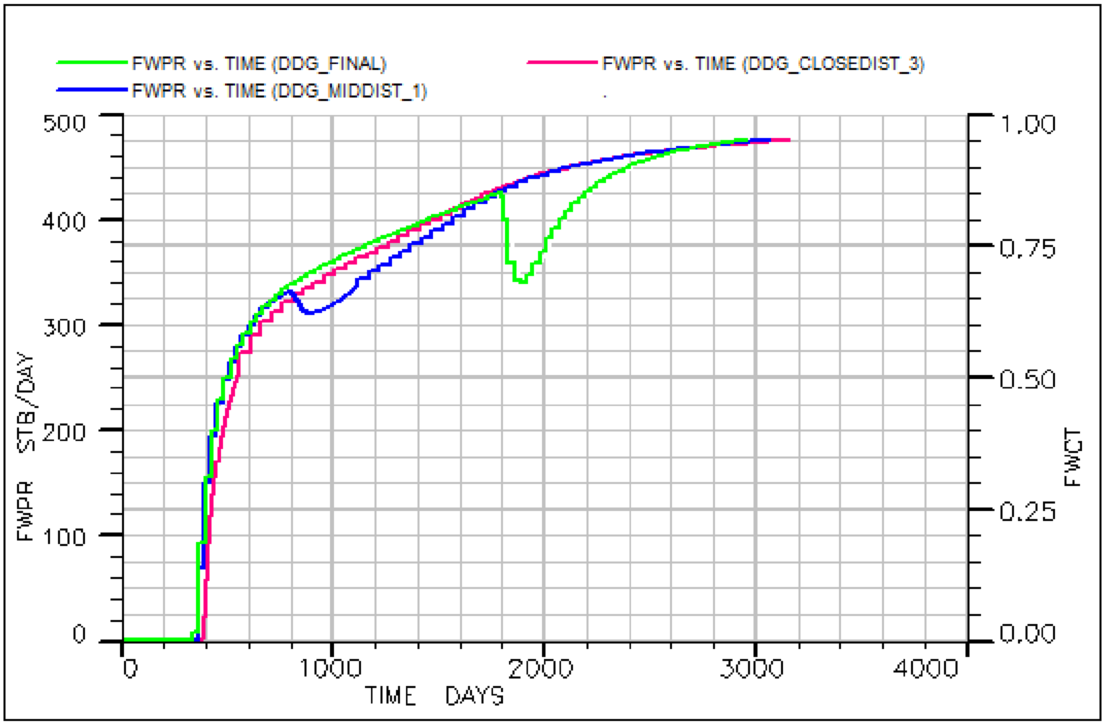

Figure 47: Water production rate and watercut of different DDG treatment times

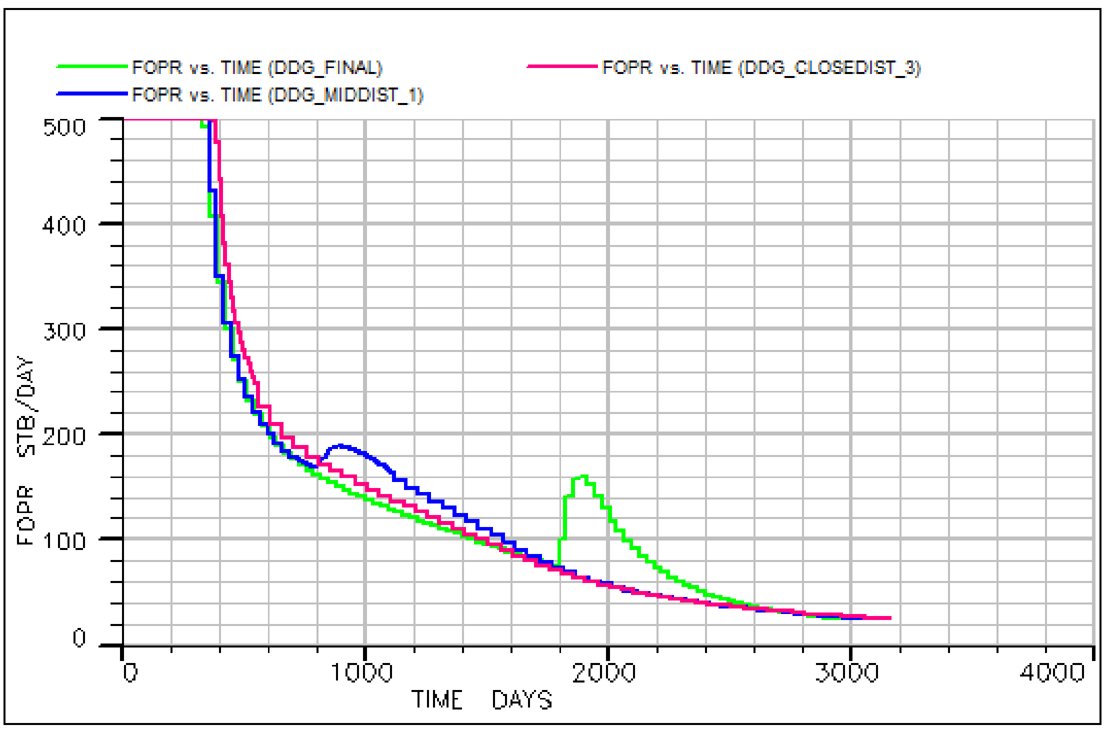

Figure 48: Oil production rate of different DDG treatment times

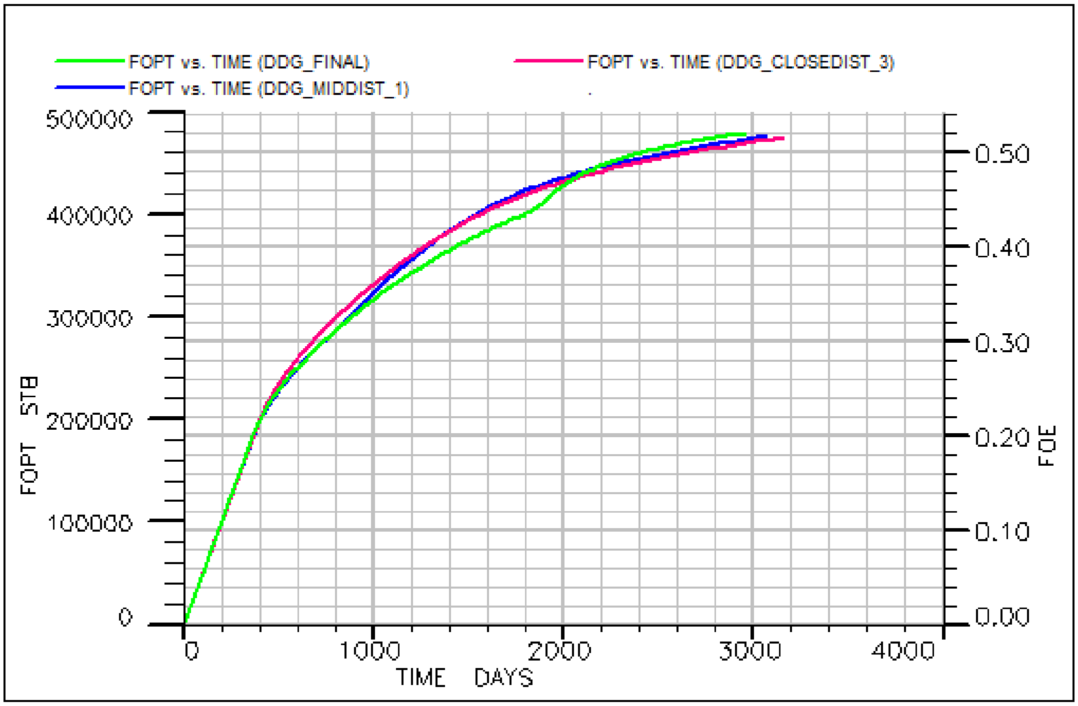

Figure 49: Cumulative oil production and recovery factors of different DDG treatment times

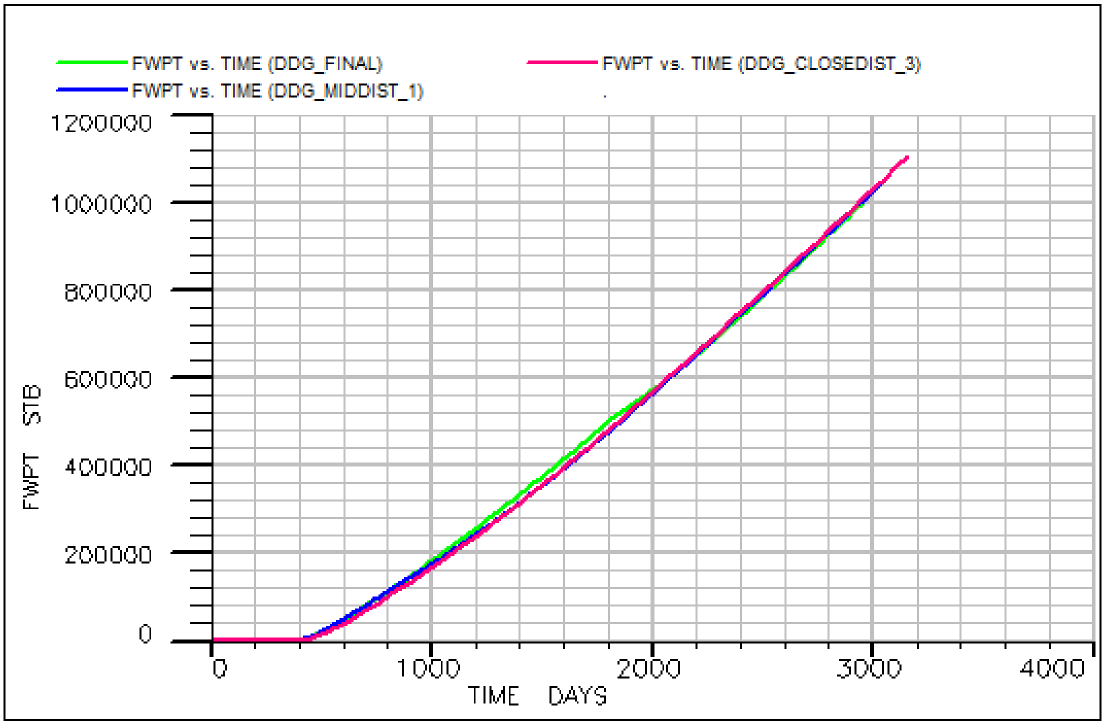

Figure 50: Cumulative water production of different DDG treatment times

6.2 Number of Plugs

Number of placed plugs has been increased and investigated. It has been assumed that it might be possible to inject one slug of particles which is activated with temperature as on base case and then second slug of different gelants can be injected which forms a gel with time. Second type of polymers can be engineered to block the intended area and divert the injected water afterwards (Figure 51 and 52).

Figure 53 demonstrates that the watercut of the model with two blocks increases with slightly slower pace and reaches the economic limit about 200 days later. There is almost no oil production rate increase observed compared to base DDG case (Figure 54). Only due to extended production time there is 1-1.5% extra oil and some water recovery compared to base DDG case (Figure 55 and 56). This outcome makes us believe that having increased number of plugs would benefit the production.

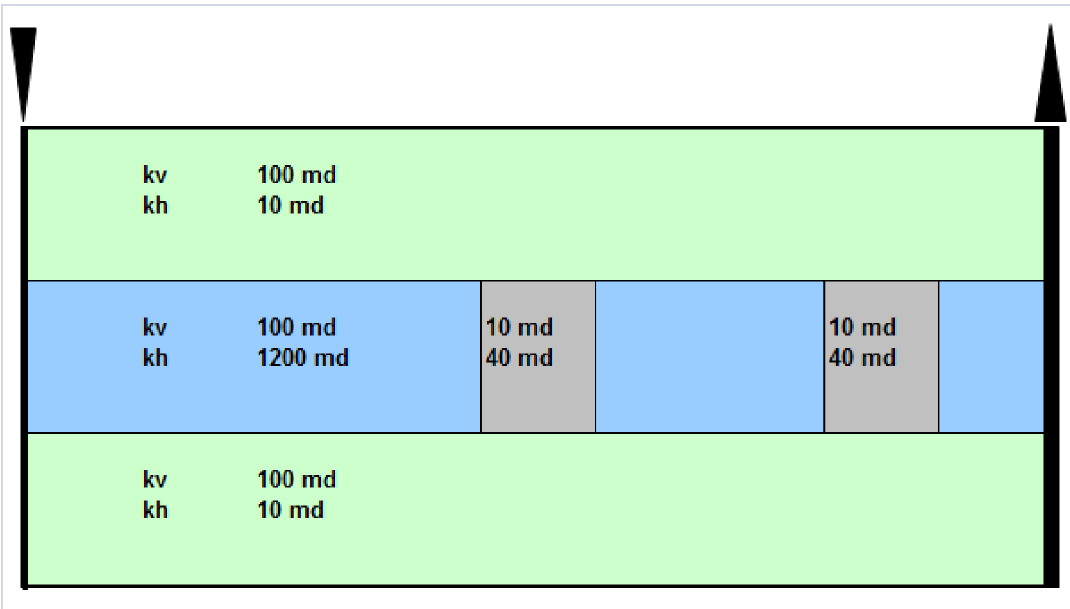

Figure 51: Illustration of two plug model

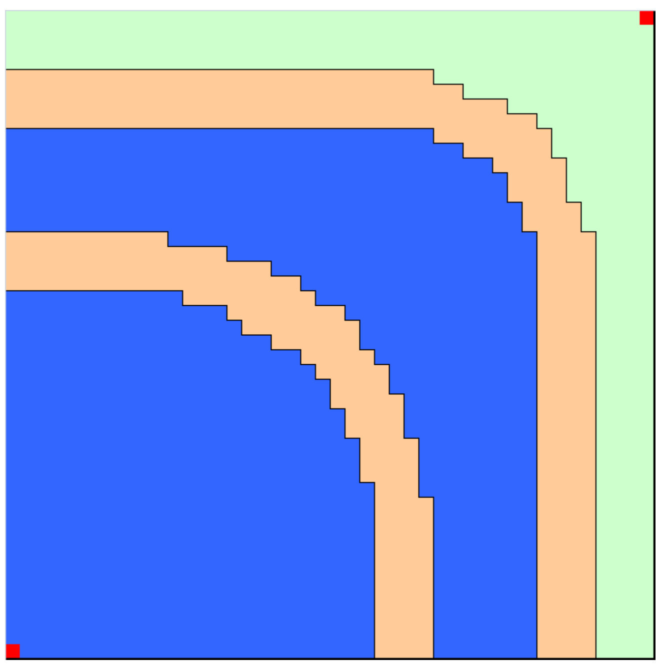

Figure 52: Plug locations

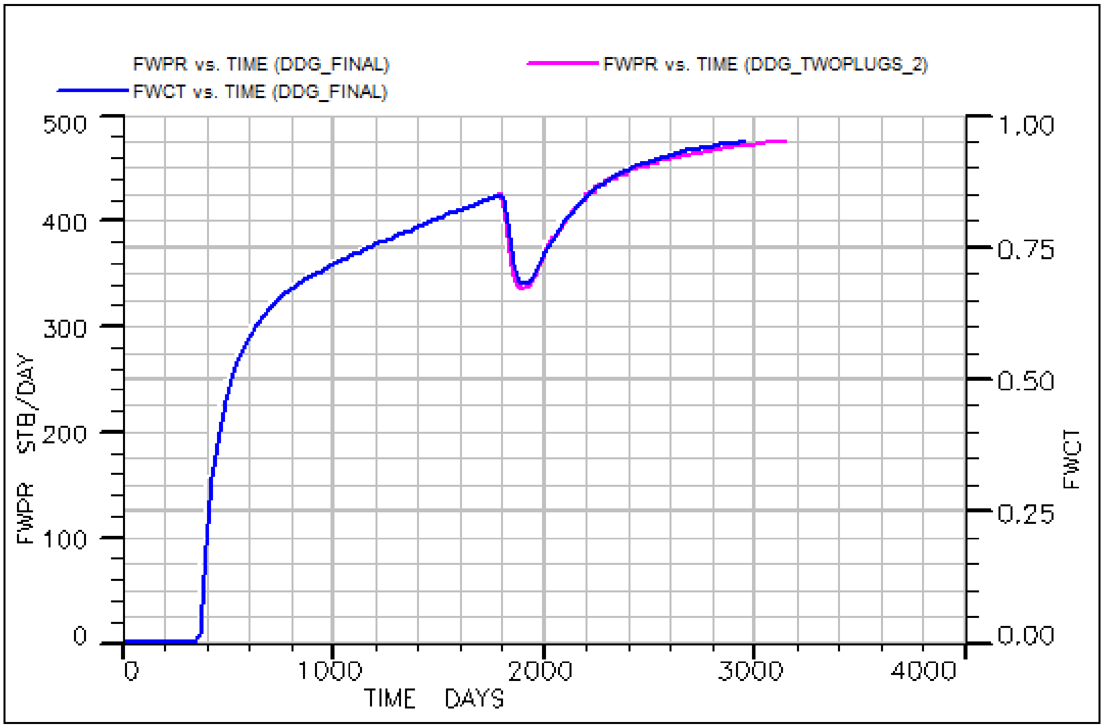

Figure 53: Water production rate and watercut of double plug DDG

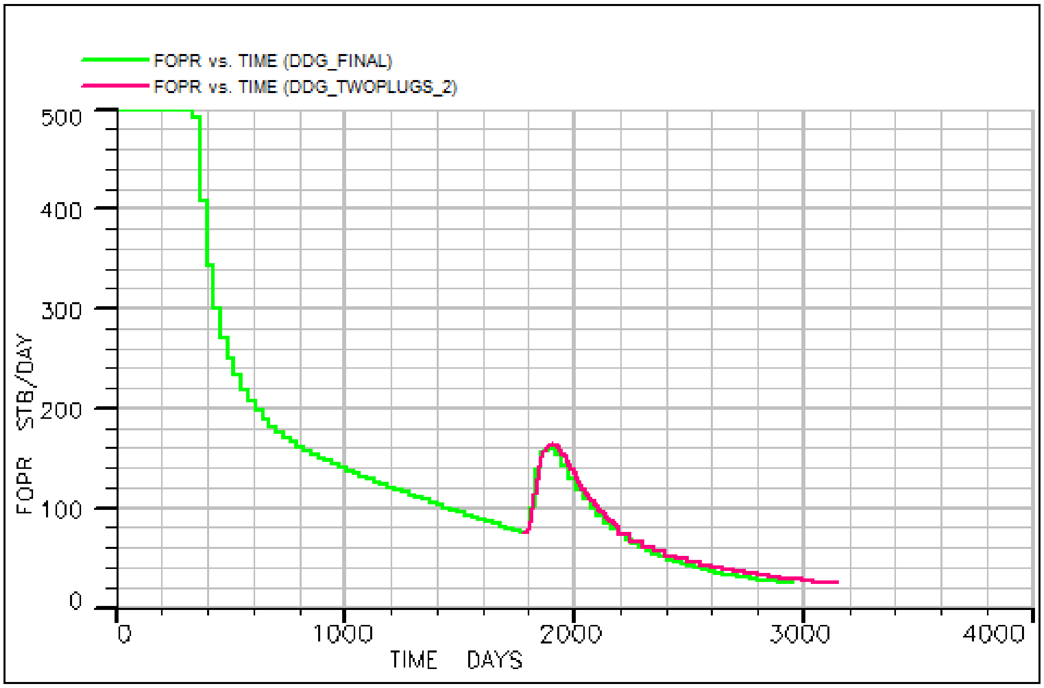

Figure 54: Oil production rate of double plug DDG

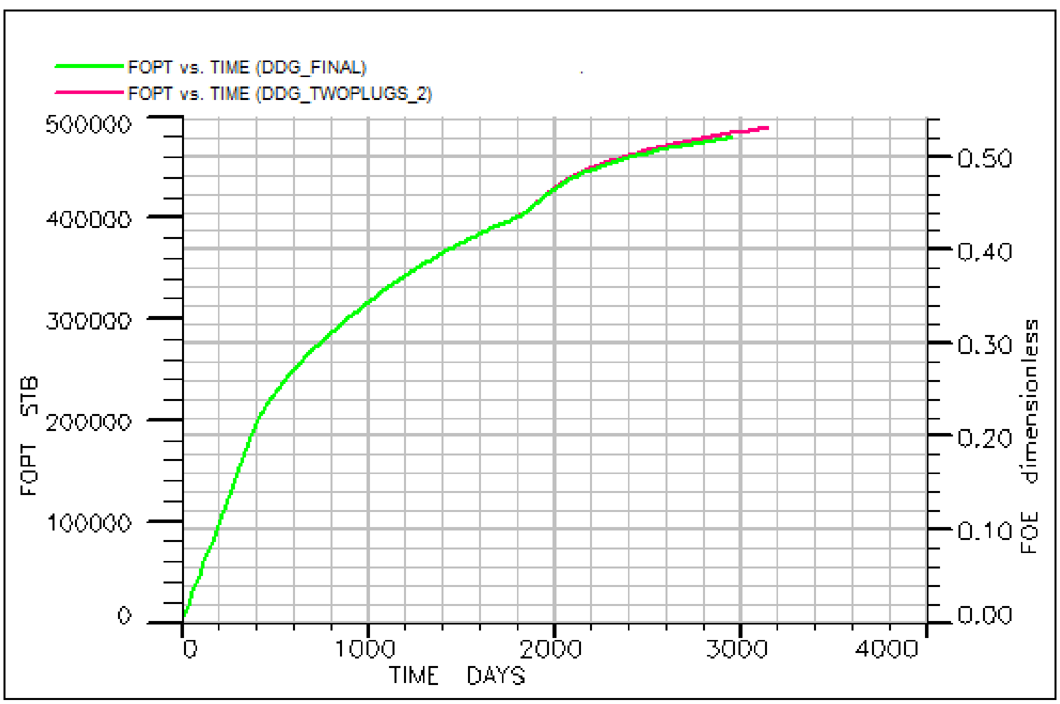

Figure 55: Cumulative oil production and recovery factor of double plug DDG

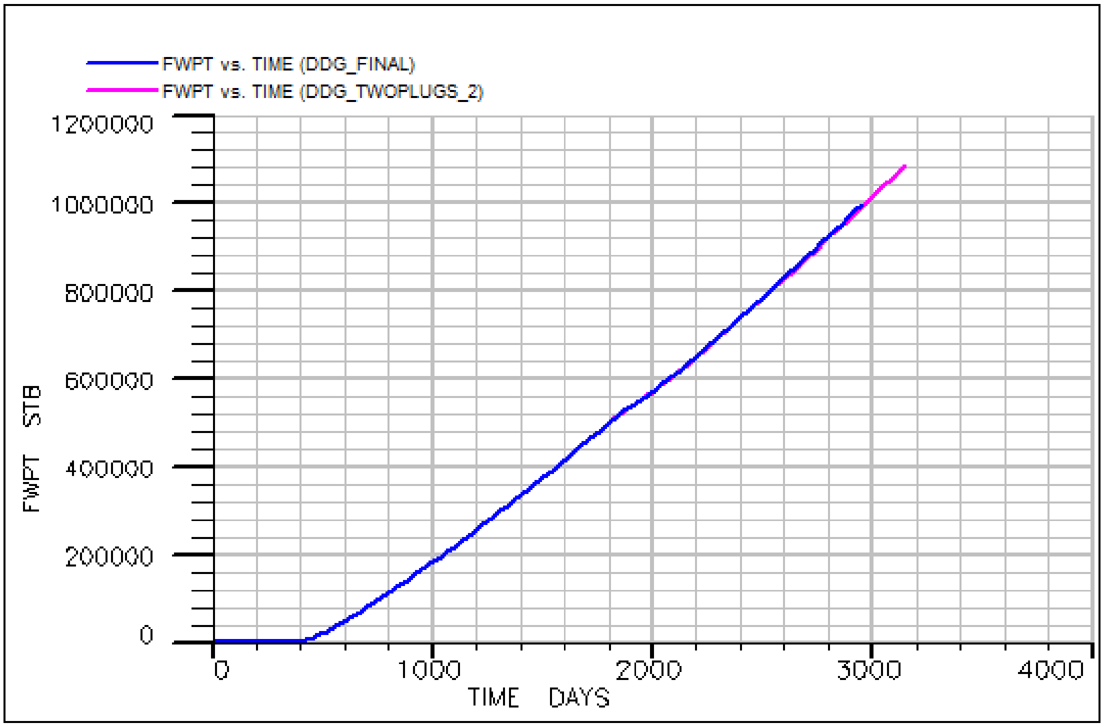

Figure 56: Cumulative water production of double plug DDG

6.3 Plug Size

Performance of different plug size has been evaluated. Treatment has been applied at the same time and location. The only difference was amount of the injected particles (Figure 57). It was expected that larger plug would create more distance for injected water to travel through the low permeability zone, thus leading to increased recovery.

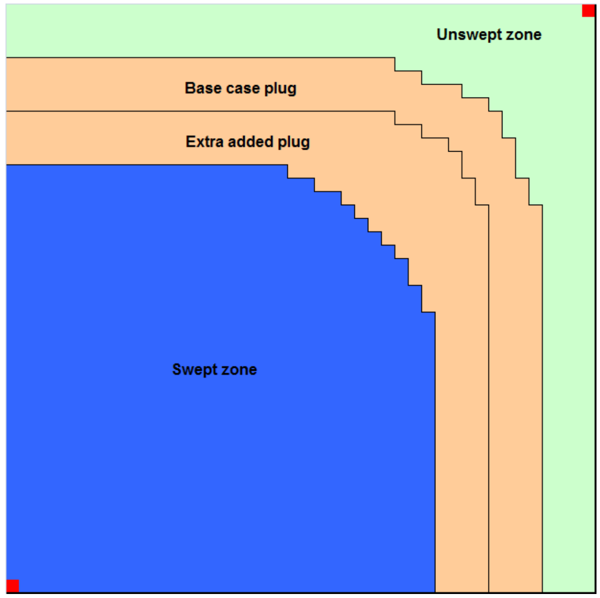

Figure 57: Diagram of larger plug size

Rapid increase in oil production rate has been observed as on base deep diversion gel model, but on this run the increase is more significant changing from 78 stb/d to 198 -stb/d compared to that of base case from 78 stb/d to 160 stb/d (Figure 58). This increase about one per cent of the oil in place to the total production (Figure 59).

Lower cumulative water production and significant decrease (Figure 60 and 61) in watercut makes this option favorable for production. Optimal size of the plug should be determined with economic analysis for the best revenue.

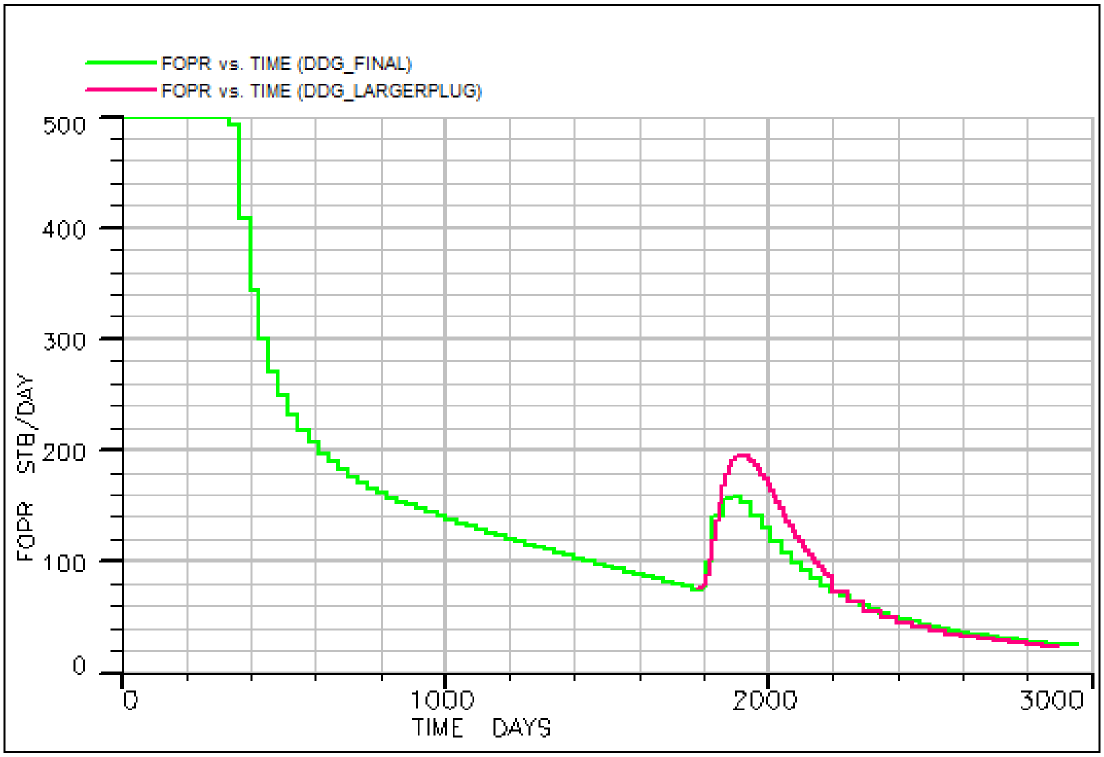

Figure 58: Oil production rate of large plug DDG

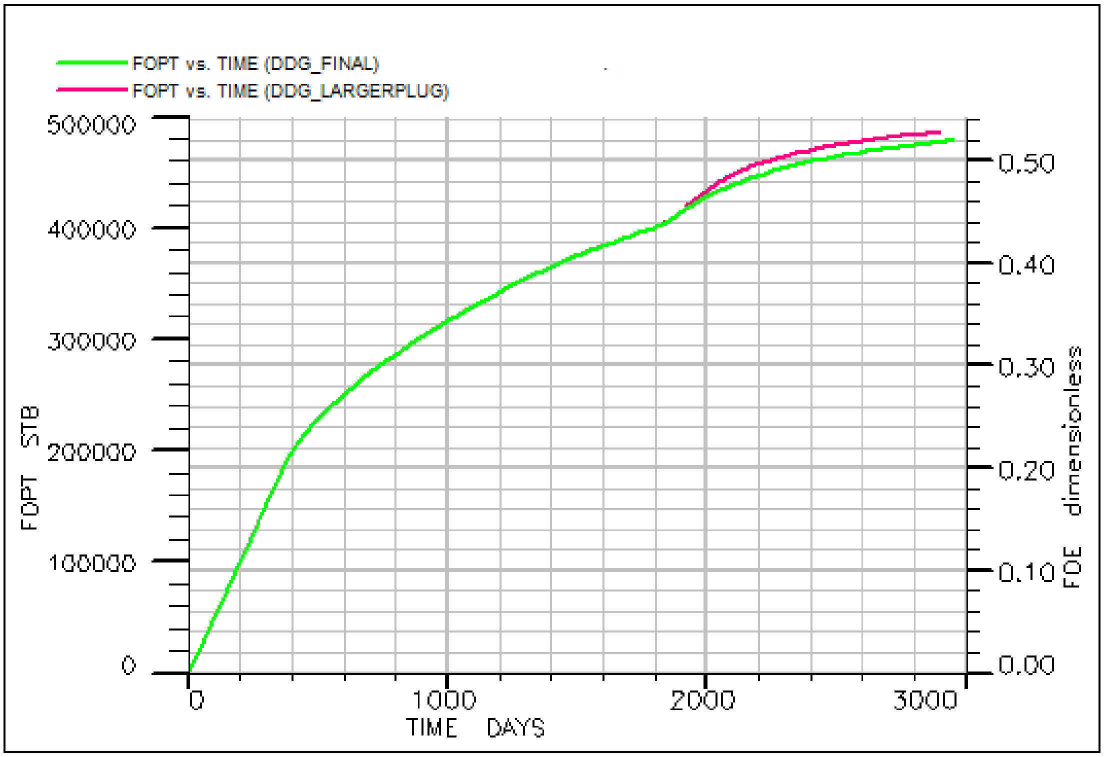

Figure 59: Cumulative oil production and recovery factor of large plug DDG

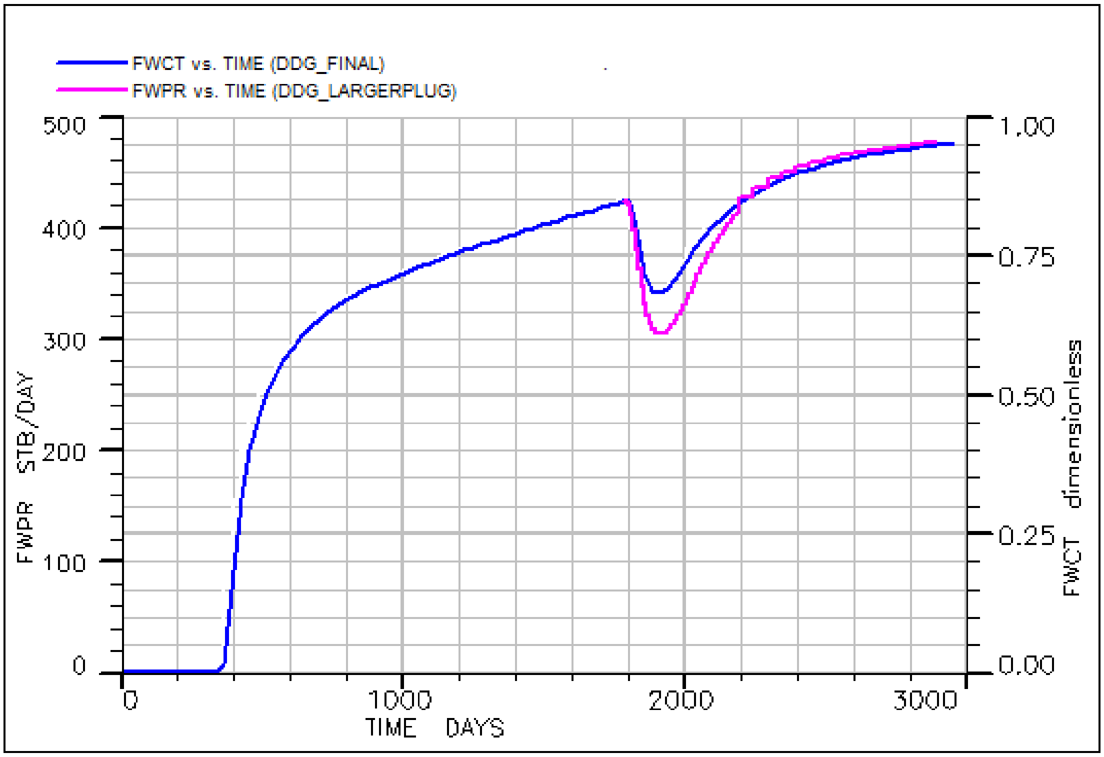

Figure 60: Water production rate and watercut of large plug DDG

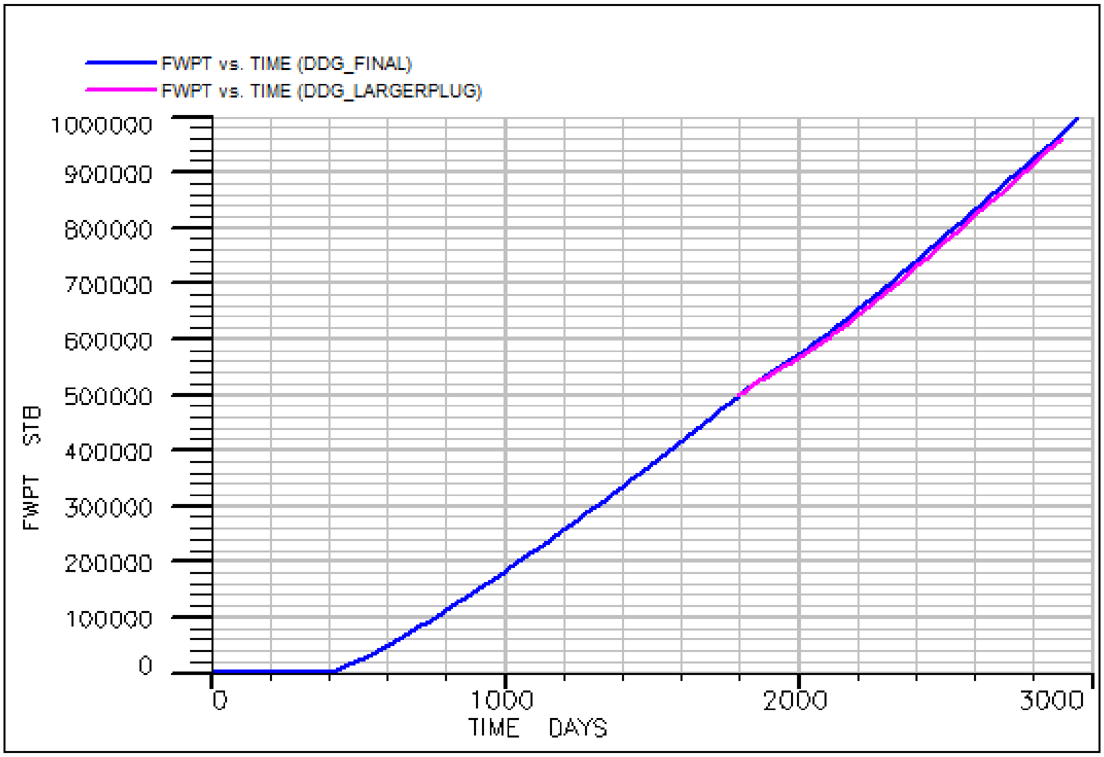

Figure 61: Cumulative water production of large plug DDG

6.4 Viscosity

Viscosity is one of the most important parameters determining the production performance. Current situation where high permeability streak occurs viscosity of the oil has significant effect on breakthrough time, sweep efficiency and overall on recovery. Effect of viscosity on the performance of water flooding and EOR treatment has been studied with a sensitivity run.

Base case had relatively light oil with API gravity of 34.2 and viscosity of 2 cp. It was decided to increase the viscosity and study the behavior of the deep diversion gels on heavier oils. Model with API gravity of 29.5 and viscosity of 5 cp has been built. Results of this run are show on Figures 62 - 65.

Difference in viscosity resulted in slight change of temperature distribution as well. More diversion of water to the high permeability layer due to lower mobility ratio on the low perm layers observed. This leads to slightly faster movement of thermal front.

On this situation, we either had to change the location (shape) of the plug or the time of application. It's been decided to change the time, since it wouldn't affect the overall performance unlike the shape alteration. So, treatment was applied on October 2004 instead of December 2004, which was on the base case. This slight time difference is almost not notable on the overall plot.

Dashed lines on plots (Figures 62 - 65) are showing water flooding and gel treatment results for less viscous (base) case and solid lines are showing the same for higher viscosity case. As mentioned earlier, early water breakthrough occurs when high viscosity oil presents (Figure 62). Oil production rate increases more with deep diversion gel introduction on second case and this leads to higher total oil and lower water production (Figure 63 and 65).

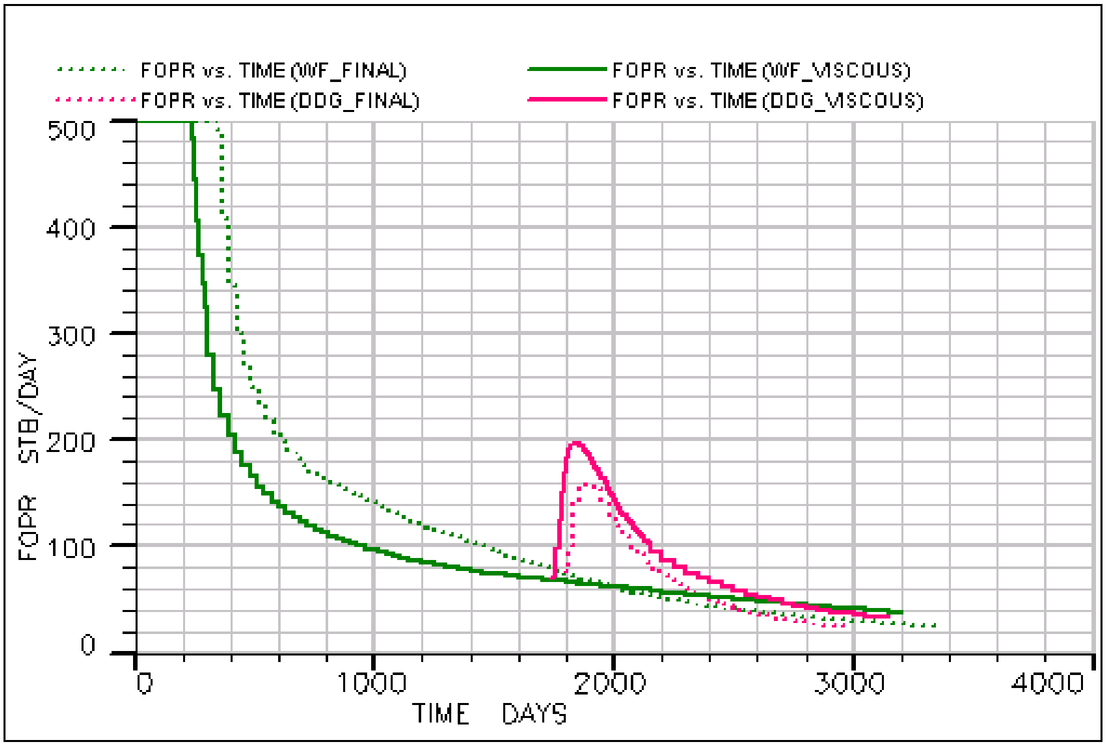

Figure 62: Oil production rate (Dashed line - low viscosity, solid line - high viscosity)

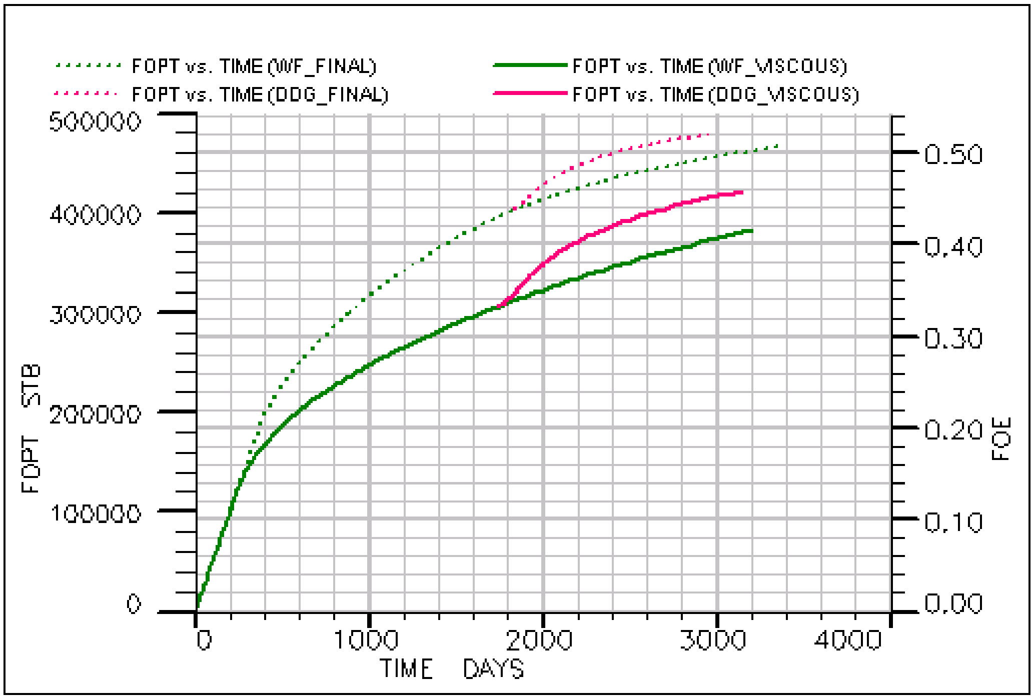

Figure 63: Cumulative oil Production and recovery factor of different viscosity oils

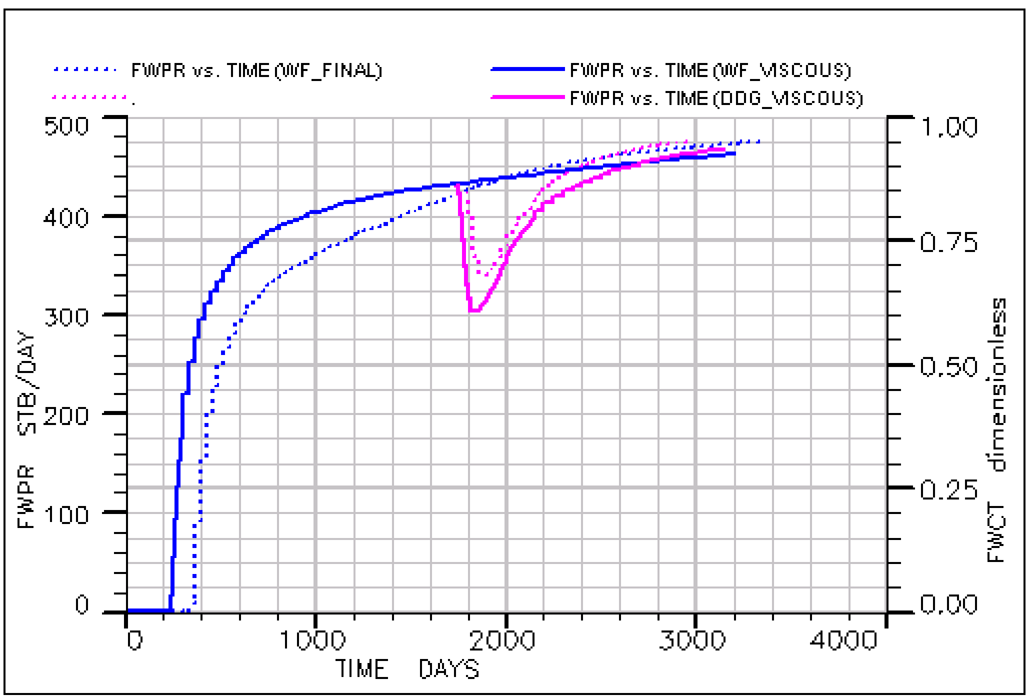

Figure 64: Water production rate and watercut of different viscosity oils

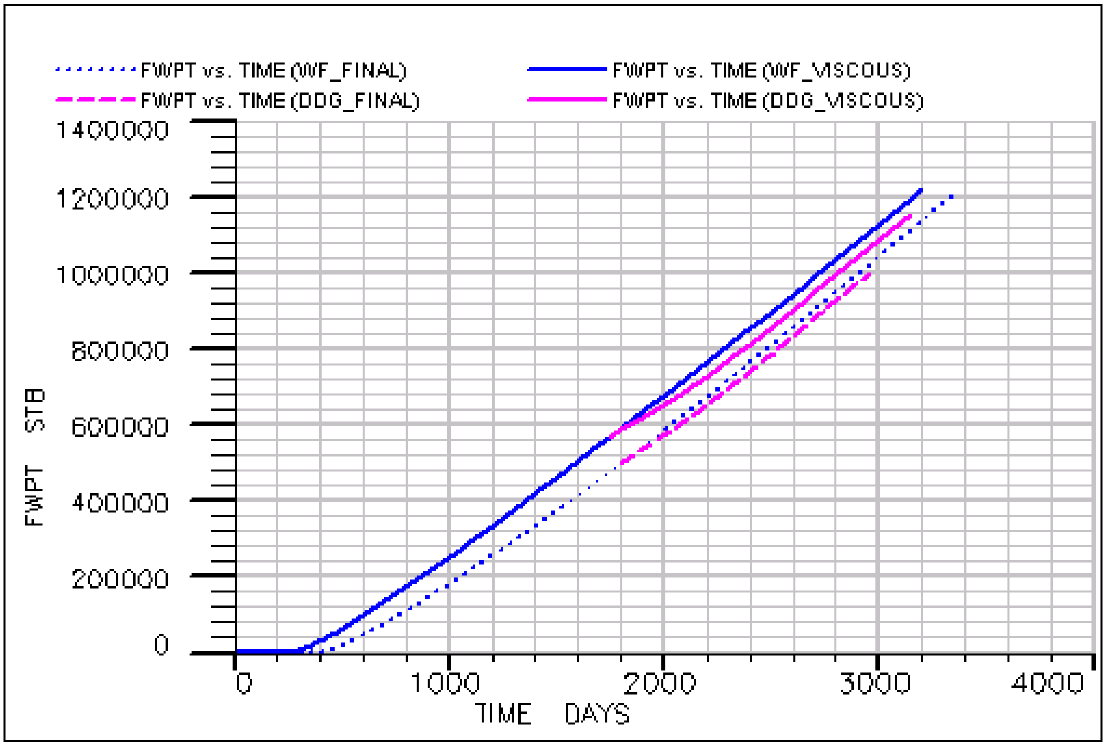

Figure 65: Cumulative water production of different viscosity oils

6.5 Five Spot Model

Base water flooding and other models were constructed based on the quarter of the 5 spot water flooding pattern. After observing results of different treatments on that model, it was important to apply them on full pattern and analyze results (Figure 66 and 67)

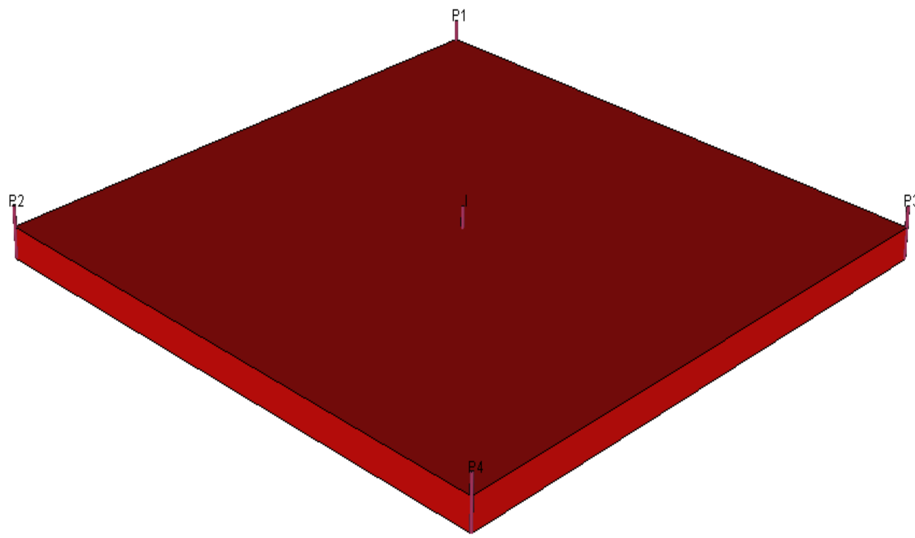

Figure 66: 3D view of full pattern

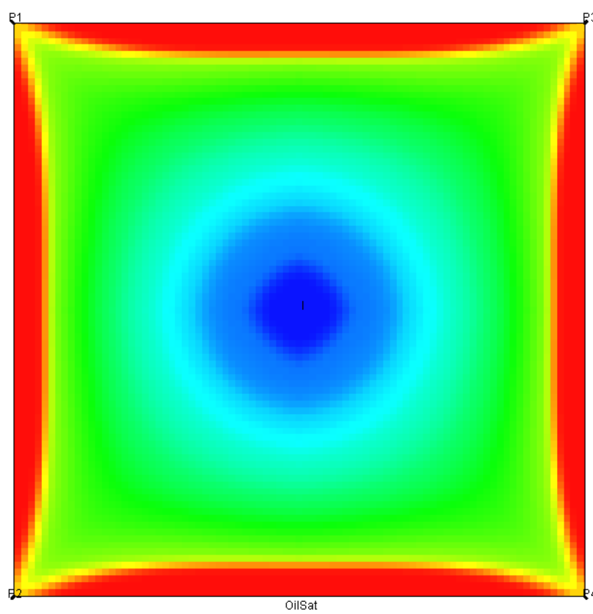

Figure 67: Top layer of full pattern after 9 years of production (oil saturation)

It was expected that the results would be the same, since models were based on the same parameter and assumptions. The only difference was in number of gridblocks. Quarter of 5 spot model had 44x44 grids and multiplying each side to two, full pattern was supposed to have 88x88 gridblocks, but due to injection well location at the center of the model, number of grids should be an odd number - 87. It was expected that this change might lead to very slight differences in results.

All figures shown below (68 - 75) has the same colors and labels. Dashed blue and red lines stand for quarter patterns' water flooding and gel treatment cases respectively and solid green and red curves represent the same parameters for full pattern respectively.

Results of two cases were almost the same and proved our expectations. Field oil recovery and watercut had the same shape and scale of change, since they both were shown with percentage. Field oil and water production rates (Figure 71 and 73) of full pattern were four times greater than that of quarter pattern, consequently leading to cumulative oil and water productions to differ four times.

Performance of each injection and production well has also been analyzed. Oil and production rates, as well as total production volumes were same for each well on these two models. These results have proved that even few percent changes can have great impact on larger scales (Table 10)

Table 10 Comparison of quarter and full pattern models

	Total Oil Prod.	*Total Water Prod.*	*W_{cut} @ Treat.*	*Recovery Factor*
Base WF	465899	1207601	85.0%	51%
Base DDG	478530	997970	68.2%	52%
	12631	**209631**	**16.8%**	**1.4%**
5 Spot WF	1862982	4713018	85.0%	51%
5 Spot DDG	1913532	3991879	68.3%	52%
	50550	**721139**	**16.7%**	**1.4%**

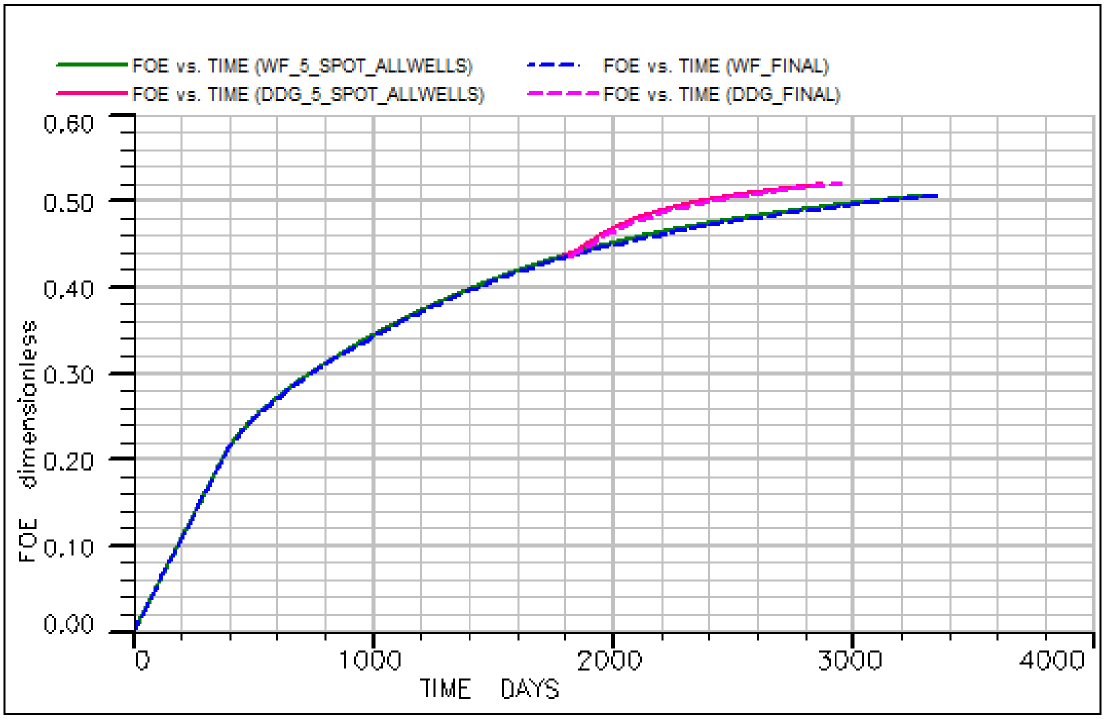

Figure 68: Oil Recoveries of quarter and full patterns

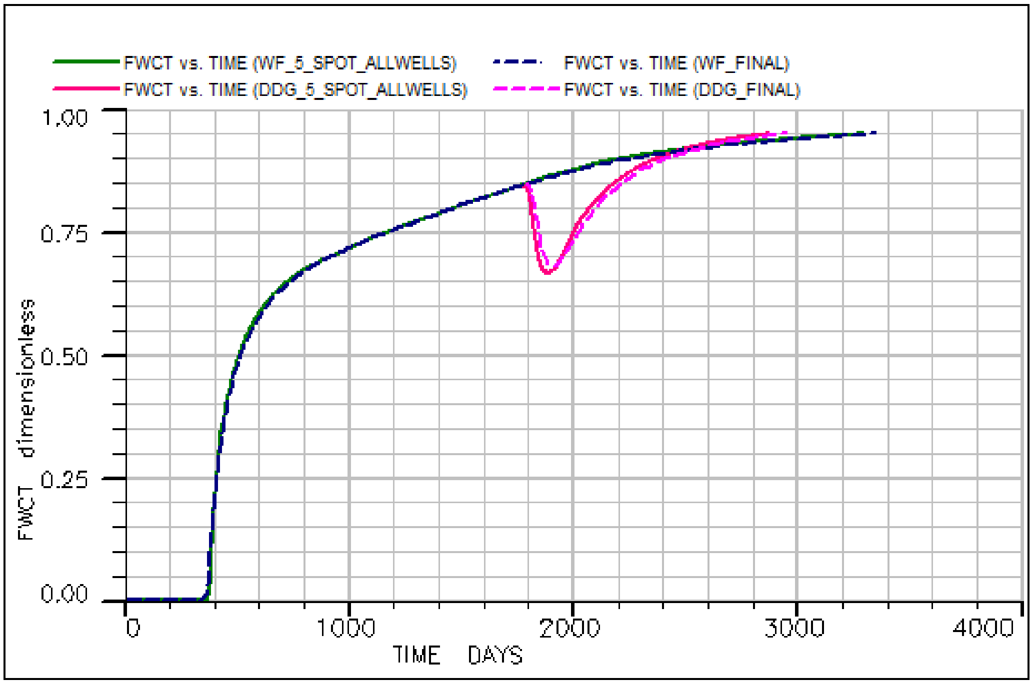

Figure 69: Watercut of quarter and full patterns

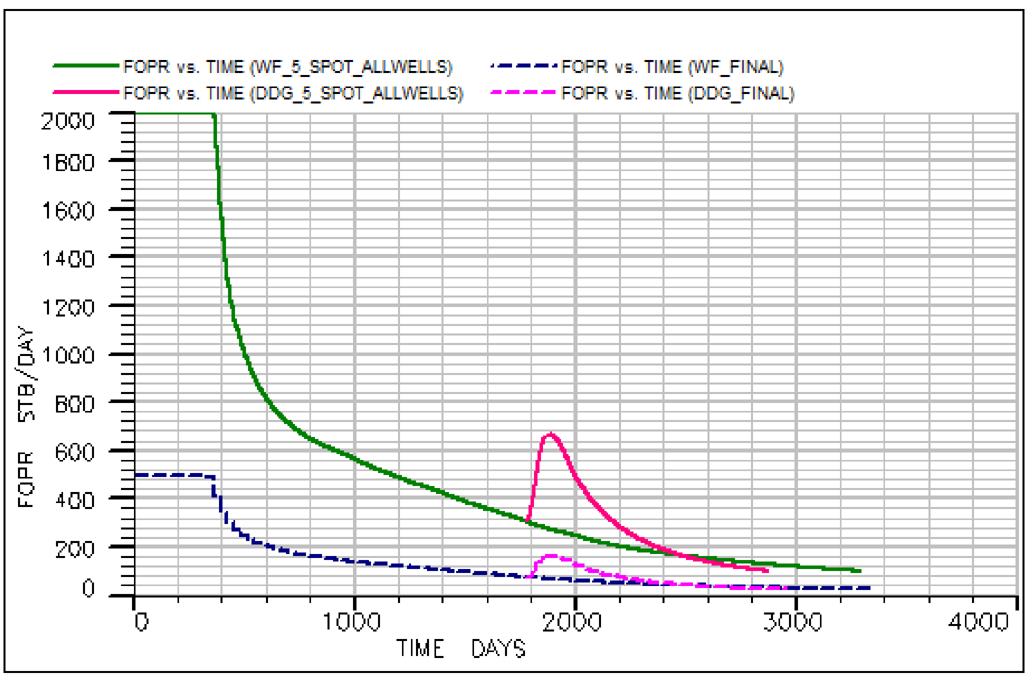

Figure 70: Field oil production rates of quarter and full patterns

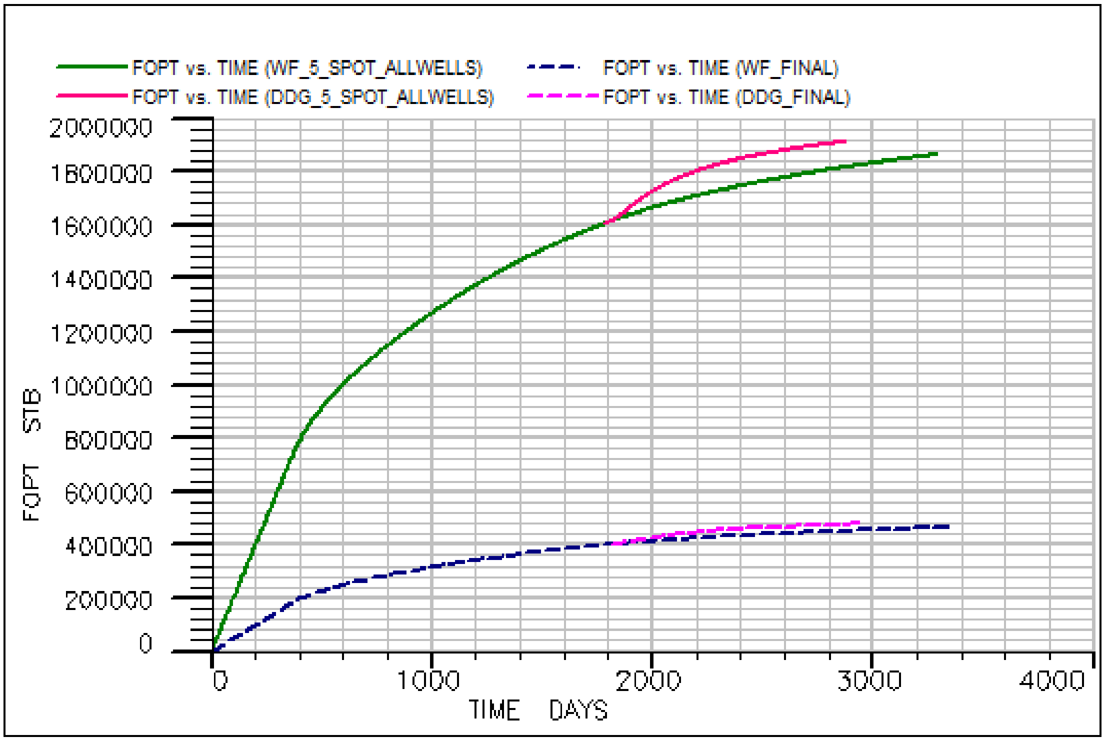

Figure 71: Total oil production from quarter and full patterns

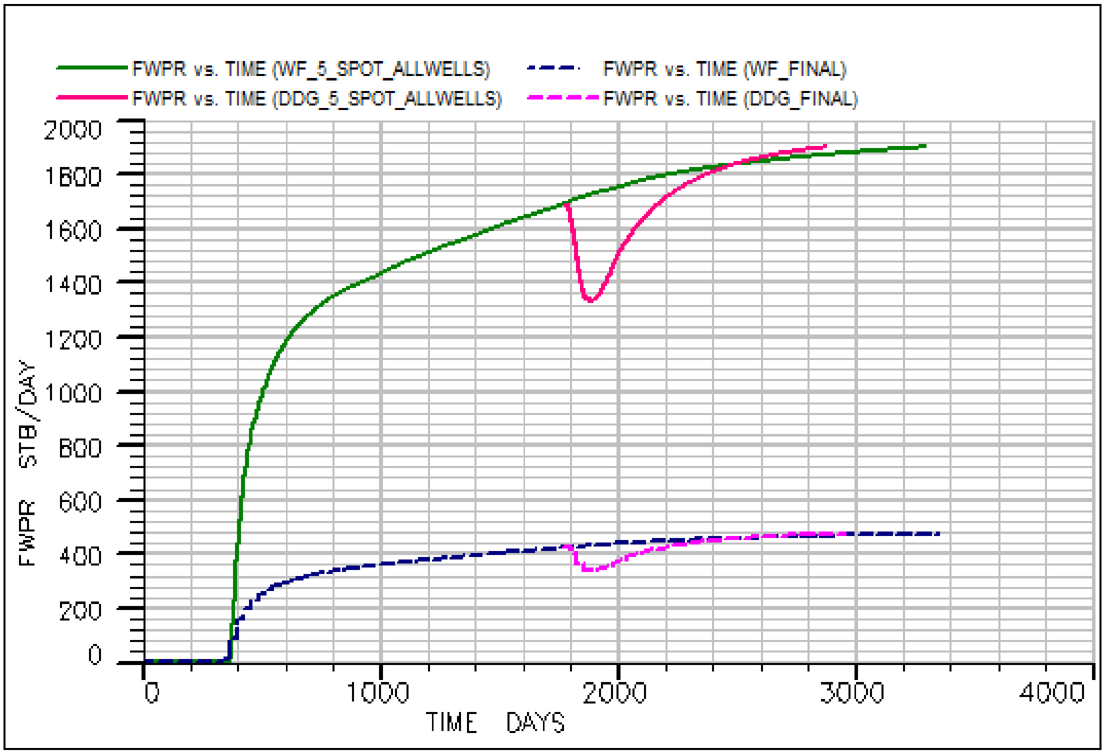

Figure 72: Field water production rates of quarter and full patterns

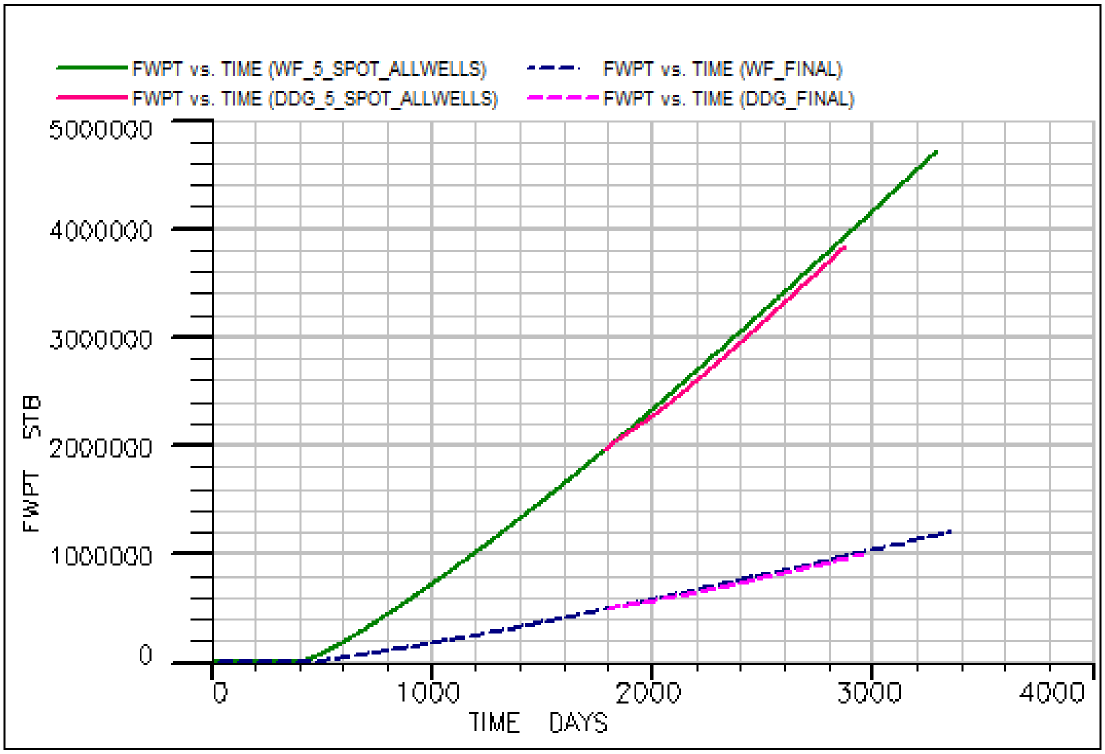

Figure 73: Total water production from quarter and full patterns

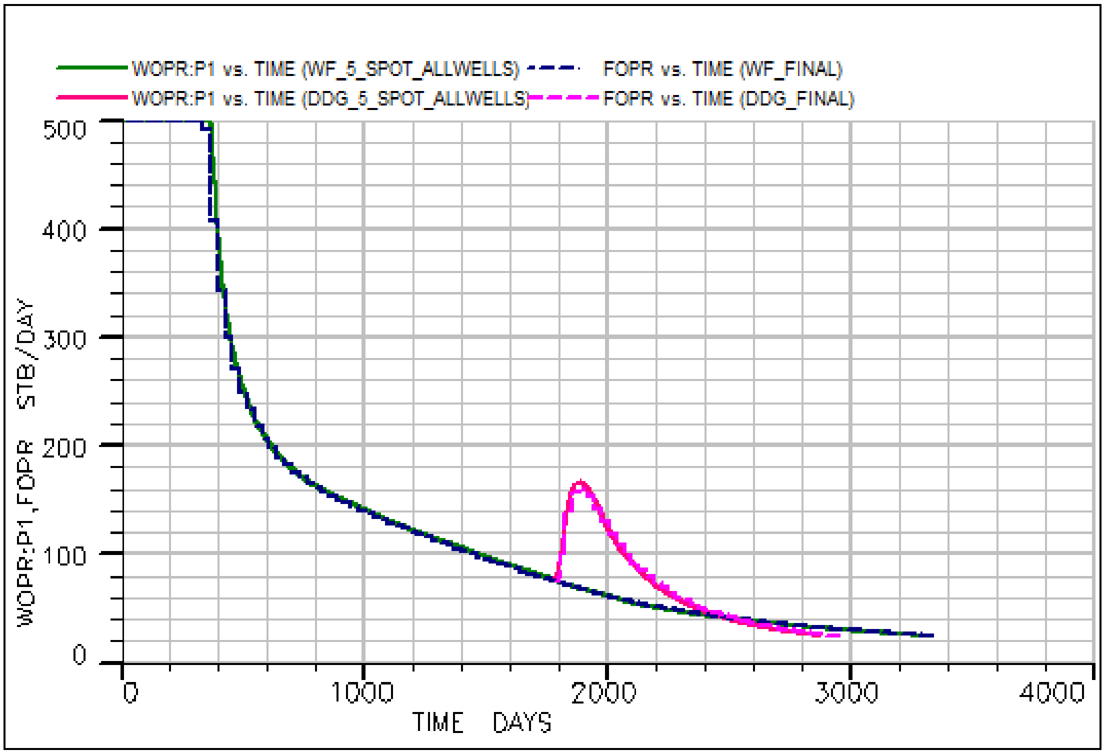

Figure 74: Oil production per well from quarter and full patterns

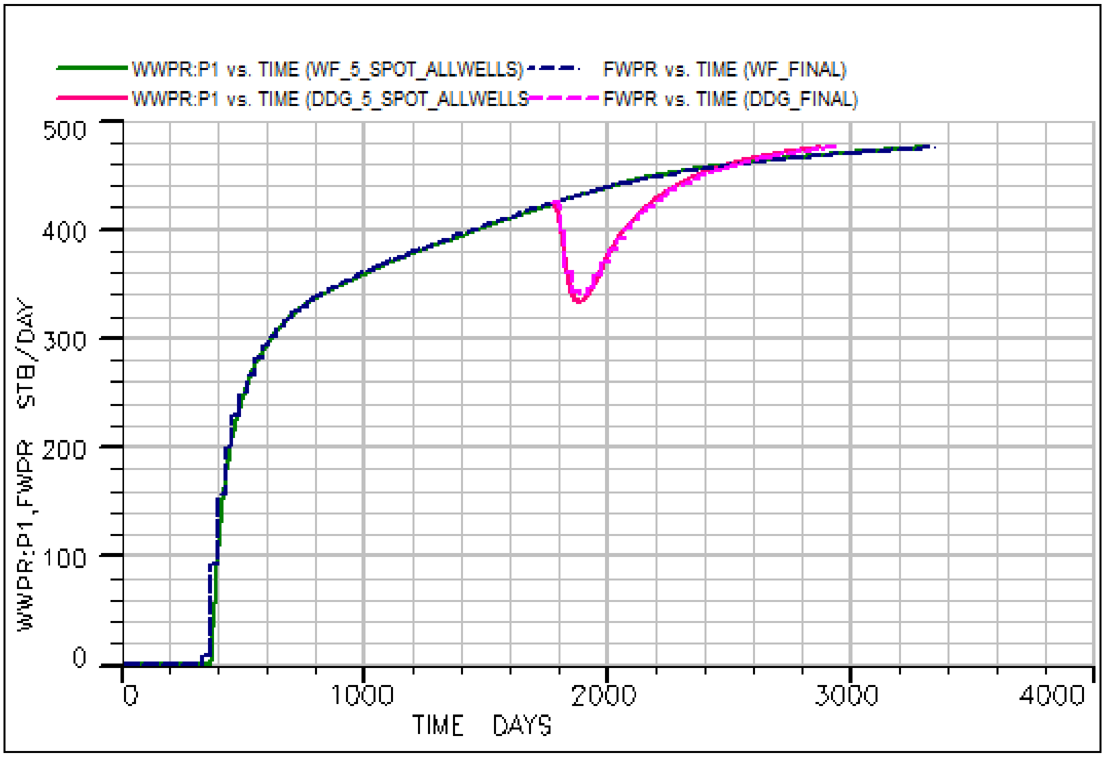

Figure 75: Water production per well of quarter and full patterns

VII ECONOMIC ANALYSIS

Economics is the crucial part of any engineering project. All treatments is intended to improve the economics of the project and make it more profitable. No matter how attractive the engineering results, economics is the key that determines whether the project will be implemented or not. Therefore it was decided to analyze economical aspects of water flooding, polymer flooding and in depth conformance control gels.

In the early life of a producing field, primary production is invariably the most lucrative end of the oil business. Costs can be accurately predicted. Decline curves, revised from time to time, can be relied upon for estimating future production and revenue, provided the price of crude oil remains fixed. However, as wells approach the stripper well class, decreasing returns make this production less and less attractive. Finally when the point is finally reached something must be done. At this spot on the decline curve, there are only three courses left:

- abandonment to prevent losses
- sale to some operator with lower overhead who can still make a small profit
- secondary recovery

In our research we will only deal with last option and will compare previously modeled treatments.

Although secondary recovery methods are able to extend the well life and increase the production for some amount, they are known with their slow rate of return and requires time and investment in order to receive the end product.

The success of a water flood project is dependent on many variables which cannot be precisely quantified. In this study we tried to cover as many affecting parameters as possible, while keeping the model simple and open for modifications depending on the case. Some of the parameters as royalty or taxes have been added to the model, but have been assumed to have minimum effect on results, not to complicate the analysis.

Economic model was based on the spreadsheet which I built for petroleum economics class. The spreadsheet was modified for water flooding project and for consideration of chemical treatments. Below are the inputs used for economic analysis. All inputs are fictitious and consistent to real life economics.

Table 11 Economic inputs

Effective Date

Starting Year:	2000
Starting Month:	1

Product Prices

Gas	$0.00 /MMbtu
Oil	$50.00 /STB
Cond	$0.00 /bbl
Price Escalation Rate:	0.000% /year
Gas Content:	1.05 Mmbtu/Mcf
Oil Gravity Price Adjustment:	$0.00 /STB

Basis Differential

Gas:	$0.00 /MMbtu
Oil:	$0.00 /STB
Cond:	$0.00 /bbl

Prodcution Taxes

Ad Valorem:	5.00%
Severence:	0.00%
Other:	0.00%

Operating Costs

Fixed:	$1,750 /Well/Month
Variable Gas:	$0.50 /Mcf
Variable Oil:	$0.05 /STB
Variable Cond:	$0.05 /bbl
Water Disposal:	$2.00 /bbl
Water Injection:	$0.20 /bbl
Polymer Injection:	$4.50 /lb

Capital Costs

D&C:	$1,000,000 /well
Tie-In:	$0 /well
Abandonment:	$50,000 /well
Facilities:	$600,000

Ownership

	BPO	APO
WI:	100.00%	100.00%
Royalty:	0.00%	0.00%
Override:	0.00%	0.00%

I Boe = 6 Mcfe

This analysis includes important factors of economics as following:

- Liquid shrinkage
- Energy content adjustment
- Basis differentials
- Capital and Operating Expenditures (CapEx and OpEx)
- Production taxes
- Ownerships.

Shrinkage and energy content is mainly used for gas productions, so they don't present in our analysis. We have assumed 100% ownership and 5% Ad Valorem taxes. Capital and operating expenditures are as shown on Table 10.

Spreadsheet uses monthly production rates which were calculated from daily production rates taken from results of simulation runs (Figure 76). Following is the monthly oil and water production rates for water flooding project.

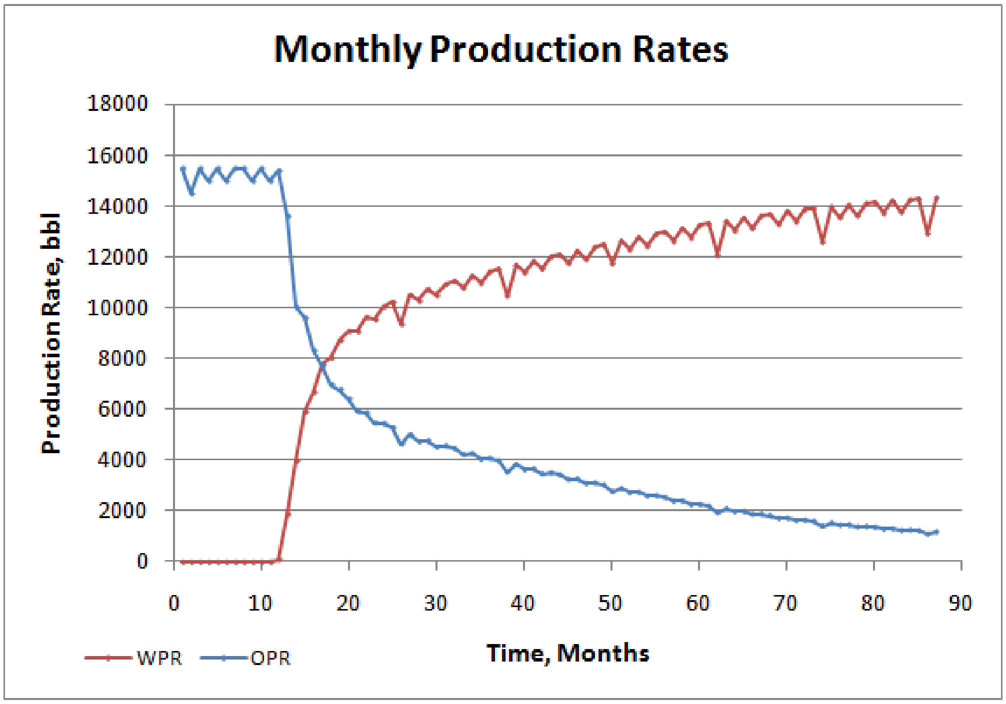

Figure 76: Monthly oil and water production rate of water flooding project

Since production results are taken from simulation runs, no altering parameters, such as permeability and porosity, effecting production was considered in economic analysis. Simple calculations are used in spreadshet, all parameters are firm and there is no probability analysis included.

Building a spreadsheet for water flooding was straightforward, since there is no chemical included into estimation. Only water and oil production rates and water injection rates were needed for calculations. Results were obtained with plugging in these parameters. Monthly and cumulative cash flow has been estimated considering sale prices, expenditures and production taxes. Net Present Values (NPV) were determines as a product of cash flow and Present Worth Factor, which was calculated by,

$$P = \frac{1}{\left(1 + \frac{i}{12}\right)^{n}}$$

where,

P - present worth factor,

i - yearly discount rate

n - number of months.

Present Worth Factor is the parameter that "converts" future income into it's present value based on discount rates. Discount rate is determined by several factors and can make a significant impact on production. Due to this, several rates have been investigated in this study and as a main comparison case 10% has been selected.

In Figure 77 monthly income of water flooding project by different discount rates have been plotted. The less discount rate case, eventually leads to higher total income Figure 78. Final report of the analysis is shown on table 11.

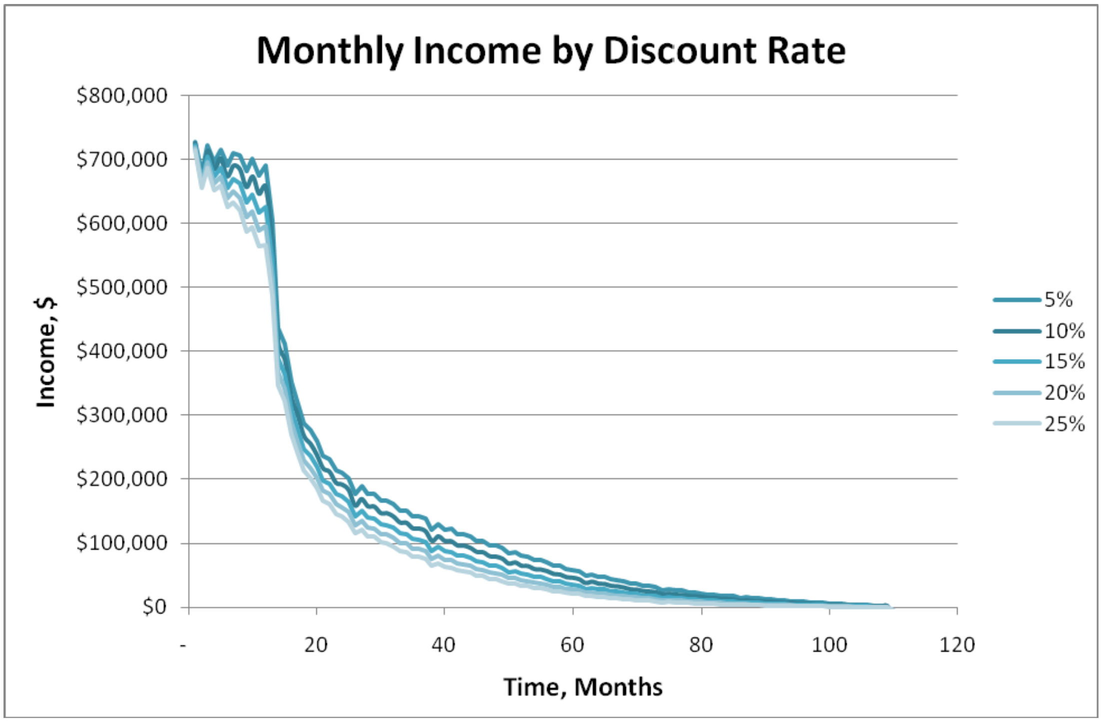

Figure 77: Monthly income of water flooding project

Figure 78: Cumulative income of water flooding project

Table 12 Economic analysis summary report of water flooding

SUMMARY ECONOMIC REPORT

Gross Project Summary (to a 100% Working Interest & a 100% Net Revenue Interest)

Year	Wellhead Production Gas (Mcf)	Wellhead Production Oil (STB)	Wellhead Prices Gas ($Mcf)	Wellhead Prices Oil ($/STB)	Revenue	CapEx & Aband.	OpEx	Taxes	Cash Flow
2000	0	182,899	$0.00	$50.00	$9,144,950	$1,600,000	$66,947	$457,248	$7,020,756
2001	0	92,109	$0.00	$50.00	$4,605,435	$0	$242,888	$230,272	$4,132,275
2002	0	54,489	$0.00	$50.00	$2,724,455	$0	$316,246	$136,223	$2,271,986
2003	0	41,649	$0.00	$50.00	$2,082,435	$0	$341,285	$104,122	$1,637,028
2004	0	31,108	$0.00	$50.00	$1,555,420	$0	$362,939	$77,771	$1,114,710
2005	0	22,359	$0.00	$50.00	$1,117,935	$0	$378,901	$55,897	$683,138
2006	0	16,543	$0.00	$50.00	$827,125	$0	$390,242	$41,356	$395,527
2007	0	12,900	$0.00	$50.00	$644,985	$0	$397,345	$32,249	$215,391
2008	0	10,367	$0.00	$50.00	$518,325	$0	$403,386	$25,916	$89,022
2009	0	1,478	$0.00	$50.00	$73,905	$50,000	$65,518	$3,695	-$45,308
Totals:	0	465,899			$23,294,970	$1,650,000	$2,965,697	$1,164,749	$17,514,525

Net Project Summary (to a Company Working Interest & Company Net Revenue Interest)

Year	Net Production Gas (Mcf)	Net Production Oil (STB)	Revenue	CapEx	Aband.	OpEx	Taxes	Cash Flow	OpEx /Boe
2000	0	182,899	$9,144,950	$1,600,000	$0	$66,947	$457,248	$7,020,756	$0.37
2001	0	92,109	$4,605,435	$0	$0	$242,888	$230,272	$4,132,275	$2.64
2002	0	54,489	$2,724,455	$0	$0	$316,246	$136,223	$2,271,986	$5.80
2003	0	41,649	$2,082,435	$0	$0	$341,285	$104,122	$1,637,028	$8.19
2004	0	31,108	$1,555,420	$0	$0	$362,939	$77,771	$1,114,710	$11.67
2005	0	22,359	$1,117,935	$0	$0	$378,901	$55,897	$683,138	$16.95
2006	0	16,543	$827,125	$0	$0	$390,242	$41,356	$395,527	$23.59
2007	0	12,900	$644,985	$0	$0	$397,345	$32,249	$215,391	$30.80
2008	0	10,367	$518,325	$0	$0	$403,386	$25,916	$89,022	$38.91
2009	0	1,478	$73,905	$0	$50,000	$65,518	$3,695	-$45,308	$44.33
Totals:	0	465,899	$23,294,970	$1,600,000	$50,000	$2,965,697	$1,164,749	$17,514,525	$6.37

All Measures to Company Interests

Present Value

PV0:	$17,514,525
PV5:	$15,886,143
PV10:	$14,506,742
PV15:	$13,326,447
PV20:	$12,306,915
PV25:	$11,418,421

PWI:	9.07	
Payout:	2	Months
Well Life:	9.2	Years
Max Negative Cash:	-$1,600,000	

Reserves Measures

Reserves:	465,899 Boe
F&D:	3.43 /Boe

Economic analysis for polymer flooding have also been performed where monthly production and injection rate inputs were as folwing (Figures 79 and 81).

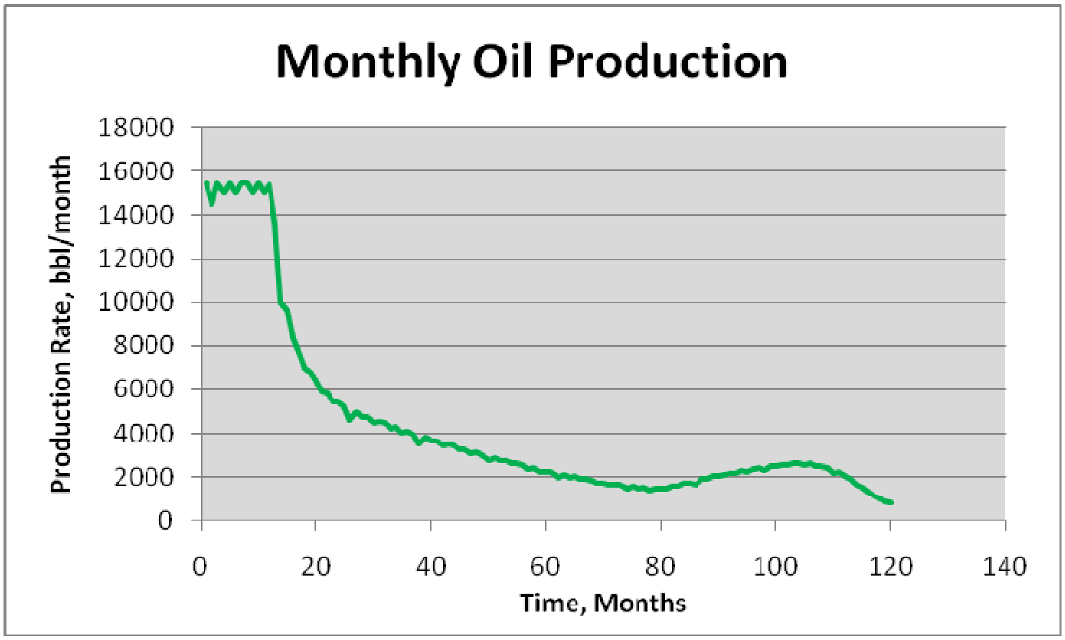

Figure 79: Monthly oil production of polymer flooding project

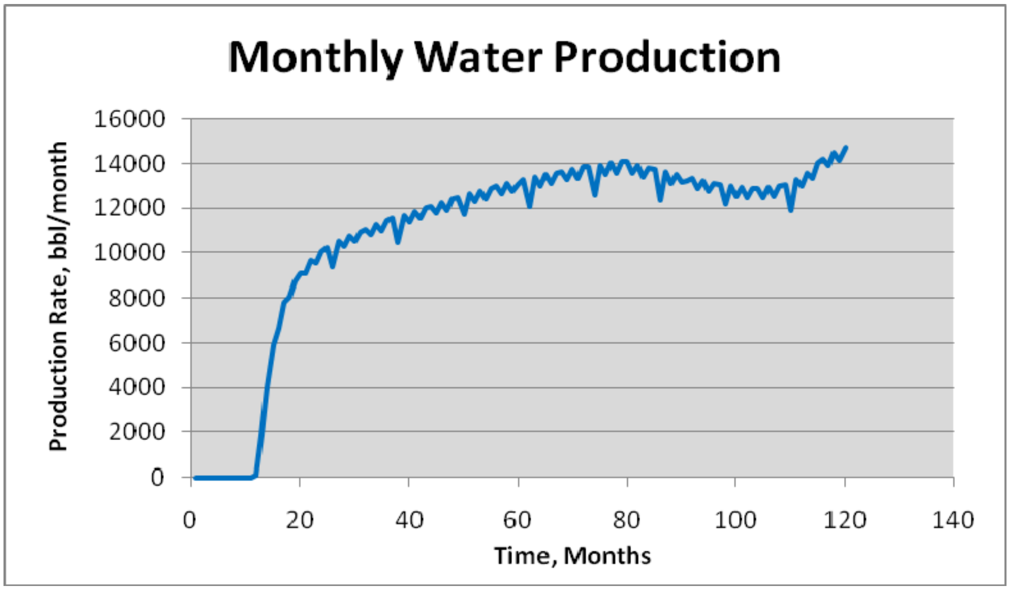

Figure 80: Monthly water production of polymer flooding project

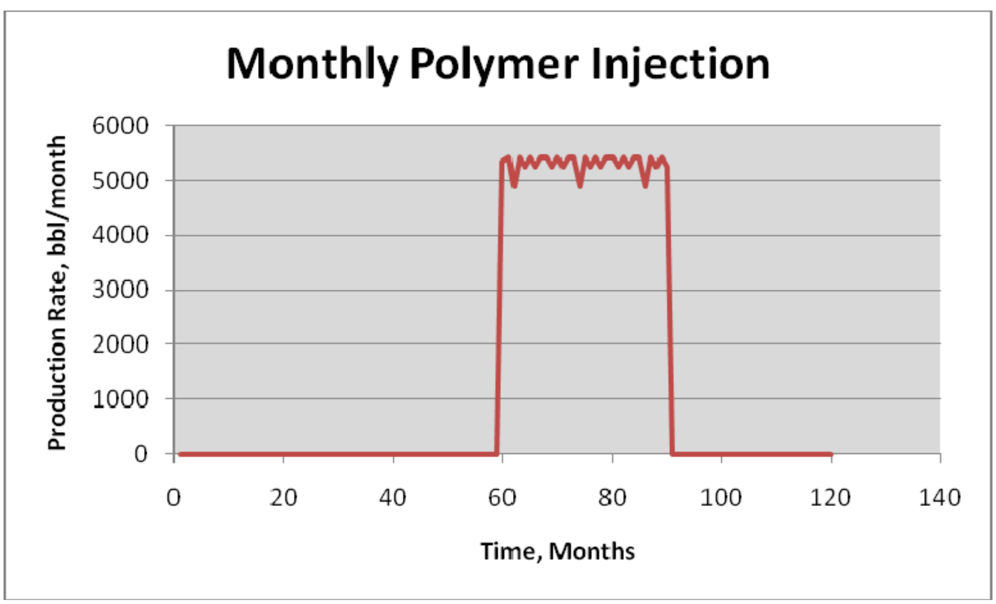

Figure 81: Monthly polymer injection

Polymer price for 1000 ppm polymer (0.35 ppb) is assumed to be $4.50 per pound. Price varies for polymer concentration alters - $3.00 for 600 ppm and $6.00 for 1500 ppm polymer has been assumed. Plots of monthly and cumulative cash flow (figures 82 and 83) demonstrate the economic behaviour of polymer flooding project. One can notice the drop in monthly income which occurs from polymer injection till increase in oil production and may not be favorable case for the company. Overal results and report of the case is show on table 12.

Economic analysis also covered the sensitivities for polymer concentration. As it was discussed on previous chapter, higher concentration of polymer yields to increased recovery of the hydrocarbon, whereas requires more expenditure for injection. One can notice the steeper decrease earlier and increase on later stages of monthly income curve of 1500 ppm case (Figure 84). Decrease is due to higher outlay for polymer while incremental oil hasn't been produced yet and increase is due to higher income from increased production as a result of treatment. Thus all sensitivity cases lead to similar total cashflow as shown on Figure 85.

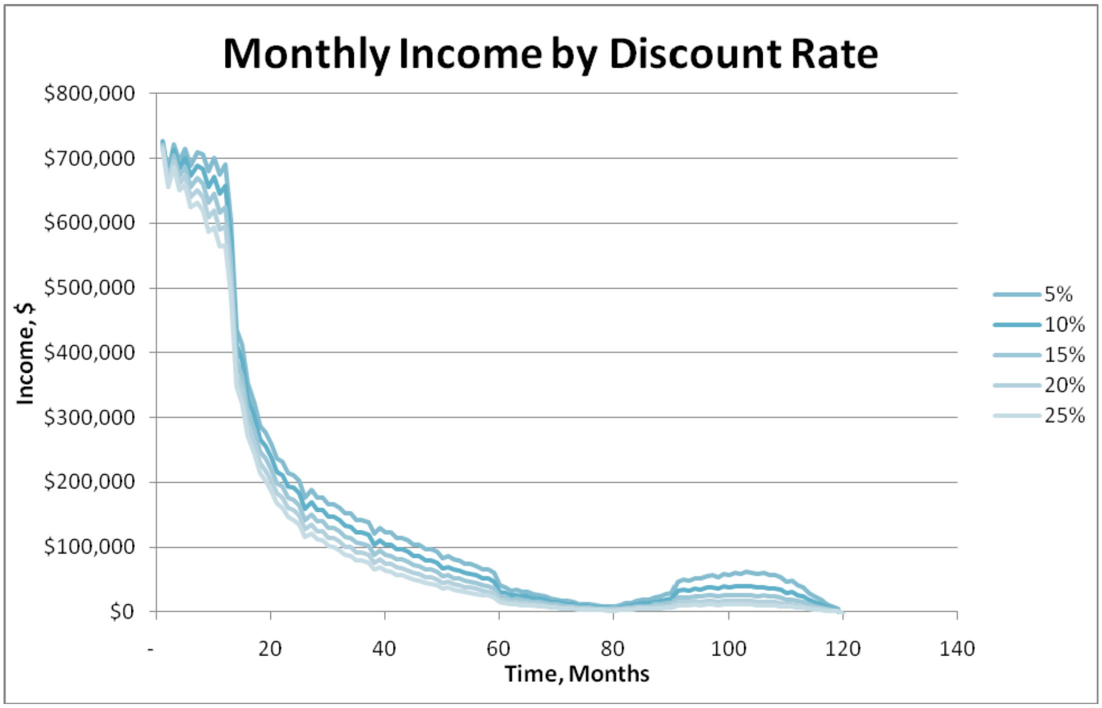

Figure 82: Monthly income of polymer flooding project

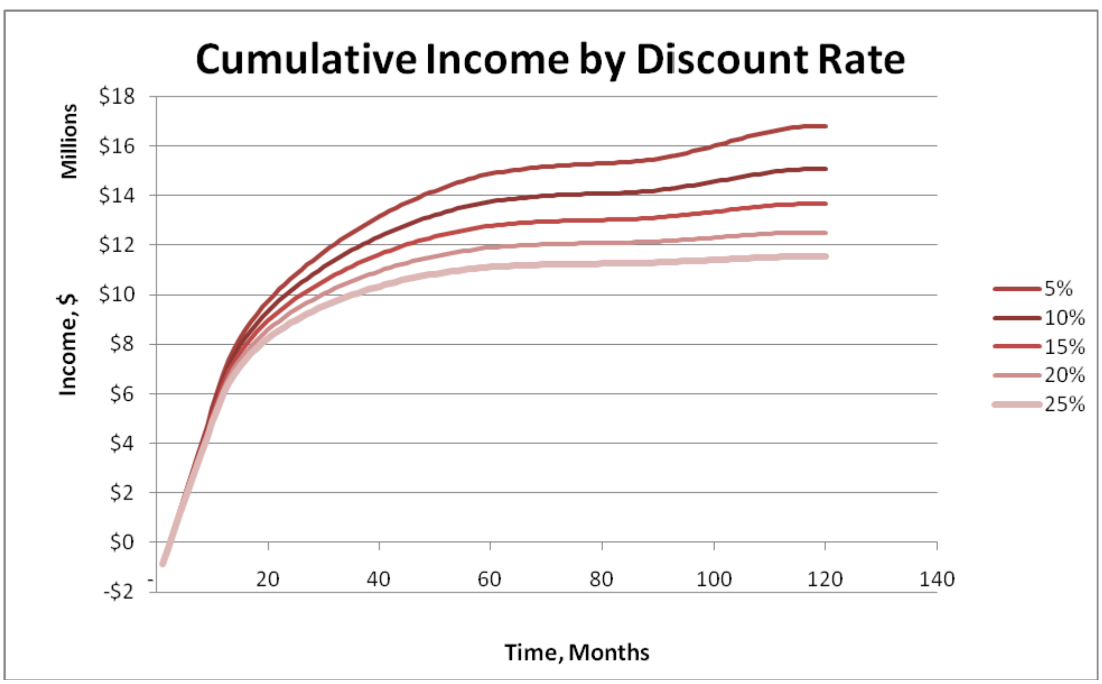

Figure 83: Cumulative income of polymer flooding project

Table 13 Economic summary report of polymer flooding

SUMMARY ECONOMIC REPORT

Gross Project Summary (to a 100% Working Interest & a 100% Net Revenue Interest)

	Wellhead Production		Wellhead Prices						
Year	Gas (Mcf)	Oil (STB)	Gas ($Mcf)	Oil ($/STB)	Revenue	CapEx & Aband.	OpEx	Taxes	Cash Flow
2000	0	182,899	$0.00	$50.00	$9,144,950	$1,600,000	$66,947	$457,248	$7,020,756
2001	0	92,109	$0.00	$50.00	$4,605,435	$0	$242,888	$230,272	$4,132,275
2002	0	54,489	$0.00	$50.00	$2,724,455	$0	$316,246	$136,223	$2,271,986
2003	0	41,649	$0.00	$50.00	$2,082,435	$0	$341,285	$104,122	$1,637,028
2004	0	31,110	$0.00	$50.00	$1,555,510	$0	$386,593	$77,776	$1,091,142
2005	0	22,836	$0.00	$50.00	$1,141,790	$0	$665,408	$57,090	$419,293
2006	0	18,240	$0.00	$50.00	$911,985	$0	$674,370	$45,599	$192,016
2007	0	24,532	$0.00	$50.00	$1,226,610	$0	$517,200	$61,331	$648,080
2008	0	30,184	$0.00	$50.00	$1,509,215	$0	$364,740	$75,461	$1,069,014
2009	0	19,034	$0.00	$50.00	$951,700	$50,000	$385,384	$47,585	$468,731
Totals:	0	517,082			$25,854,085	$1,650,000	$3,961,060	$1,292,704	$18,950,321

Net Project Summary (to a Company Working Interest & Company Net Revenue Interest)

	Net Production								
Year	Gas (Mcf)	Oil (STB)	Revenue	CapEx	Aband.	OpEx	Taxes	Cash Flow	OpEx /Boe
2000	0	182,899	$9,144,950	$1,600,000	$0	$66,947	$457,248	$7,020,756	$0.37
2001	0	92,109	$4,605,435	$0	$0	$242,888	$230,272	$4,132,275	$2.64
2002	0	54,489	$2,724,455	$0	$0	$316,246	$136,223	$2,271,986	$5.80
2003	0	41,649	$2,082,435	$0	$0	$341,285	$104,122	$1,637,028	$8.19
2004	0	31,110	$1,555,510	$0	$0	$386,593	$77,776	$1,091,142	$12.43
2005	0	22,836	$1,141,790	$0	$0	$665,408	$57,090	$419,293	$29.14
2006	0	18,240	$911,985	$0	$0	$674,370	$45,599	$192,016	$36.97
2007	0	24,532	$1,226,610	$0	$0	$517,200	$61,331	$648,080	$21.08
2008	0	30,184	$1,509,215	$0	$0	$364,740	$75,461	$1,069,014	$12.08
2009	0	19,034	$951,700	$0	$50,000	$385,384	$47,585	$468,731	$20.25
Totals:	0	517,082	$25,854,085	$1,600,000	$50,000	$3,961,060	$1,292,704	$18,950,321	$7.66

All Measures to Company Interests

Present Value

PV0:	$18,950,321
PV5:	$16,777,270
PV10:	$15,055,736
PV15:	$13,661,225
PV20:	$12,508,176
PV25:	$11,536,987

PWI:	9.41	
Payout:	2	Months
Well Life:	10.0	Years
Max Negative Cash:	-$1,600,000	

Reserves Measures

Reserves:	517,082 Boe
F&D:	3.09 /Boe

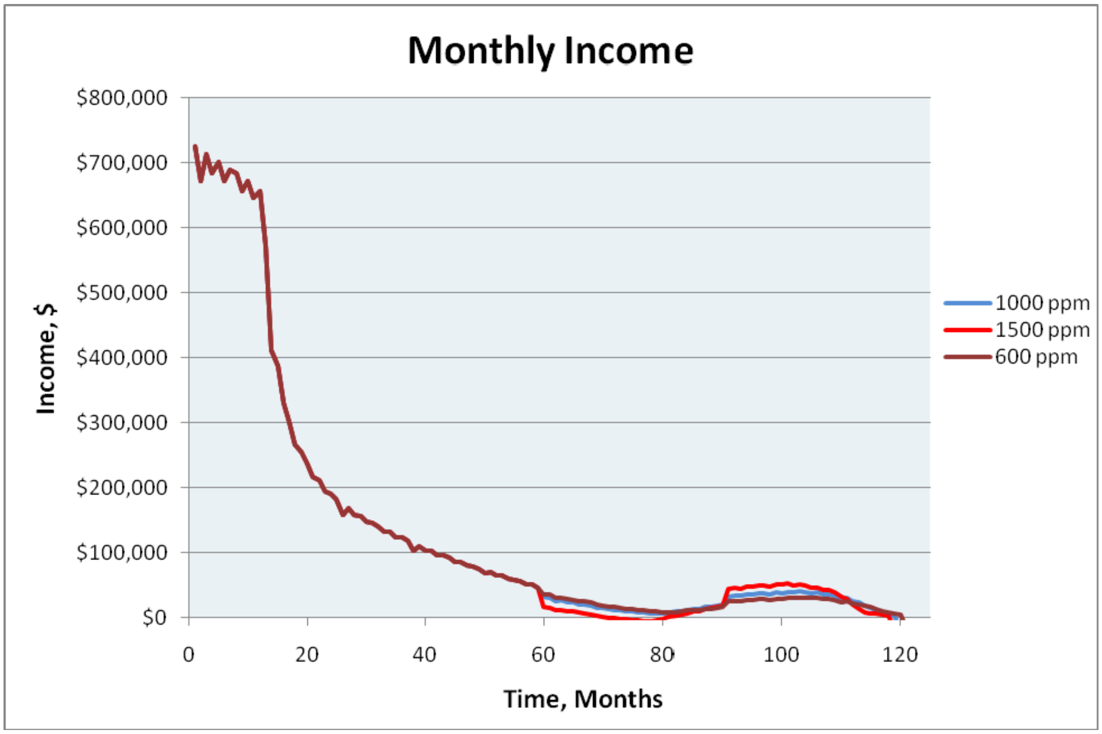

Figure 84: Monthly income of various polymer concentrations

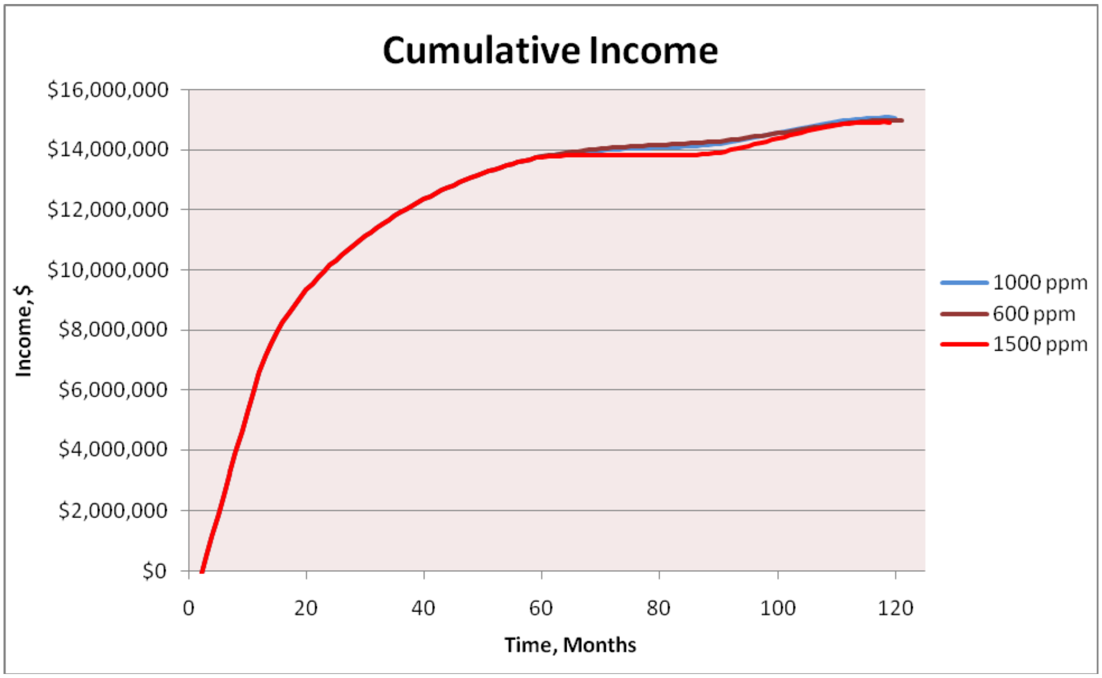

Figure 85: Total income of various polymer concentrations

Rate inputs for economic spreadsheet of deep diverting gels were taken from simulation results and were as following (Figures 86 and 87).

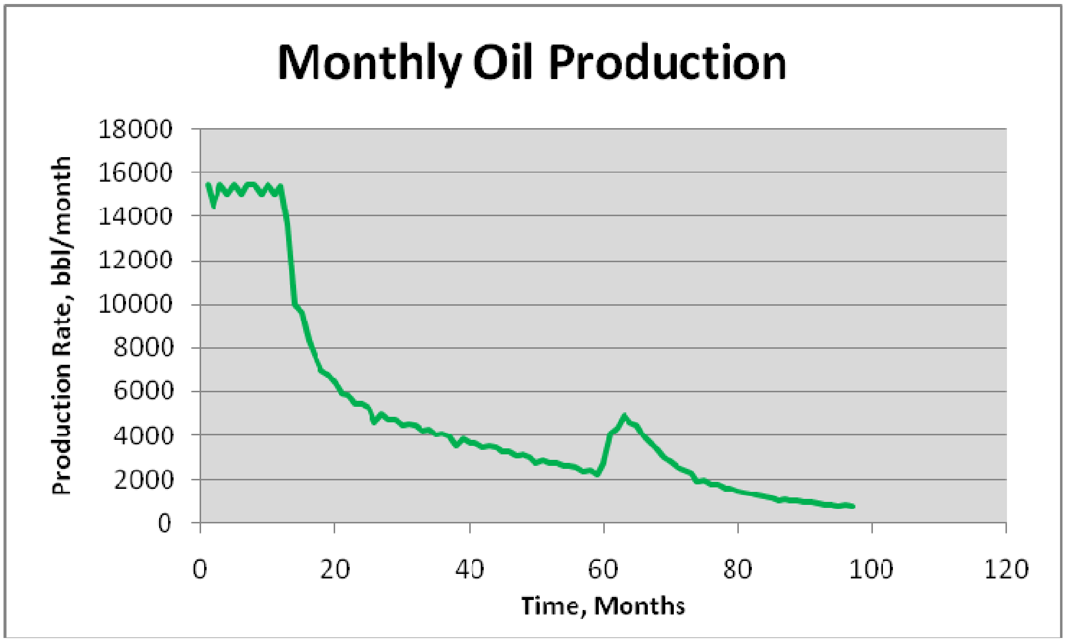

Figure 86: Monthly oil production of DDG project

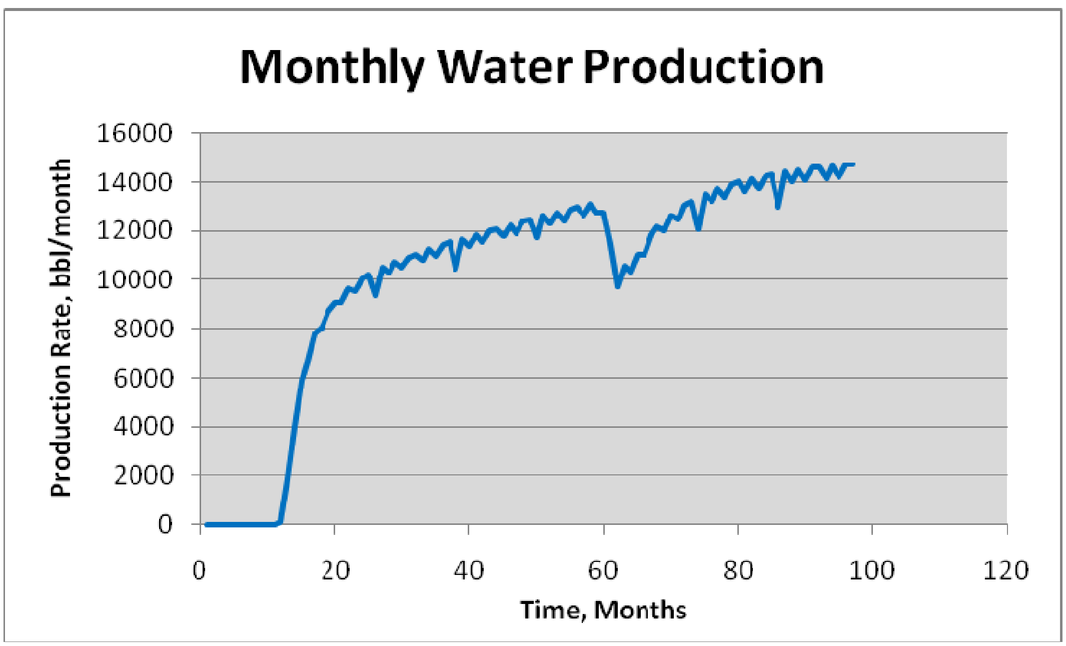

Figure 87: Monthly water production of DDG project

There was only finaly plug modeled on simulation run and was no actual particle injected in order to great the blocking zone. Due to this assumption there was no polymmer or particle injection rate available as a simulation run result to use as input for economic analysis.

Amount of injected polymer has been calculated from the volume of solution that filled the pore volume to create the blocking zone (Table 14). Obtained total injected polymer amount has been distributed by time steps as shown on figure 88.

Table 15 and Figures 89 and 90 demonstrate results obtained from the economic analysis.

Table 14 Polymer estimation for DDG

Total plugged cell volume	**1364219**	ft^3
Plugged cell pore volume	***341055***	ft^3
Total volume of solution to be injected	***60744.49***	**bbl**
Total polymer to be injected	***42521.14***	**lb**

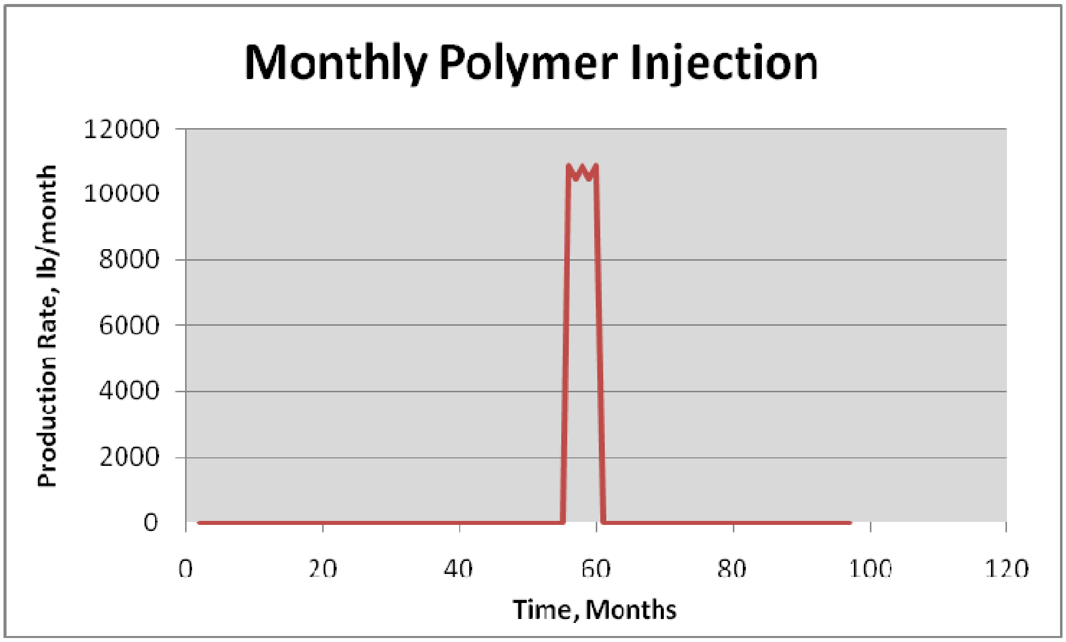

Figure 88: Monthly polymer injection of DDG project

Table 15 Economic summary report of DDG

SUMMARY ECONOMIC REPORT

Gross Project Summary (to a 100% Working Interest & a 100% Net Revenue Interest)

Year	Wellhead Production Gas (Mcf)	Wellhead Production Oil (STB)	Wellhead Prices Gas ($Mcf)	Wellhead Prices Oil ($/STB)	Revenue	CapEx & Aband.	OpEx	Taxes	Cash Flow
2000	0	182,899	$0.00	$50.00	$9,144,950	$1,600,000	$66,947	$457,248	$7,020,756
2001	0	92,109	$0.00	$50.00	$4,605,435	$0	$242,888	$230,272	$4,132,275
2002	0	54,489	$0.00	$50.00	$2,724,455	$0	$316,246	$136,223	$2,271,986
2003	0	41,649	$0.00	$50.00	$2,082,435	$0	$341,285	$104,122	$1,637,028
2004	0	31,596	$0.00	$50.00	$1,579,790	$0	$490,073	$78,990	$1,010,728
2005	0	44,238	$0.00	$50.00	$2,211,910	$0	$336,236	$110,596	$1,765,079
2006	0	19,560	$0.00	$50.00	$977,995	$0	$384,358	$48,900	$544,737
2007	0	11,222	$0.00	$50.00	$561,110	$0	$400,617	$28,056	$132,438
2008	0	761	$0.00	$50.00	$38,055	$50,000	$34,366	$1,903	-$48,214
2009	0	0	$0.00	$50.00	$0	$0	$0	$0	$0
Totals:	0	478,523			$23,926,135	$1,650,000	$2,613,016	$1,196,307	$18,466,813

Net Project Summary (to a Company Working Interest & Company Net Revenue Interest)

Year	Net Production Gas (Mcf)	Net Production Oil (STB)	Revenue	CapEx	Aband.	OpEx	Taxes	Cash Flow	OpEx /Mcfe
2000	0	182,899	$9,144,950	$1,600,000	$0	$66,947	$457,248	$7,020,756	$0.06
2001	0	92,109	$4,605,435	$0	$0	$242,888	$230,272	$4,132,275	$0.44
2002	0	54,489	$2,724,455	$0	$0	$316,246	$136,223	$2,271,986	$0.97
2003	0	41,649	$2,082,435	$0	$0	$341,285	$104,122	$1,637,028	$1.37
2004	0	31,596	$1,579,790	$0	$0	$490,073	$78,990	$1,010,728	$2.59
2005	0	44,238	$2,211,910	$0	$0	$336,236	$110,596	$1,765,079	$1.27
2006	0	19,560	$977,995	$0	$0	$384,358	$48,900	$544,737	$3.28
2007	0	11,222	$561,110	$0	$0	$400,617	$28,056	$132,438	$5.95
2008	0	761	$38,055	$0	$50,000	$34,366	$1,903	-$48,214	$7.53
2009	0	0	$0	$0	$0	$0	$0	$0	$0.00
Totals:	0	478,523	$23,926,135	$1,600,000	$50,000	$2,613,016	$1,196,307	$18,466,813	$0.91

All Measures to Company Interests

Present Value

PV0:	$18,466,813
PV5:	$16,619,149
PV10:	$15,070,531
PV15:	$13,759,863
PV20:	$12,640,005
PV25:	$11,674,379

PWI:	9.42	
Payout:	2	Months
Well Life:	8.1	Years
Max Negative Cash:	-$1,600,000	

Reserves Measures

Reserves:	478,523	Boe
F&D:	3.34	/Boe

Figure 89: Monthly income of DDG project

Figure 90 Total income of DDG project

Main purpose of the economic analysis was to investigate the profitability of deep diverting gels compared to other production enhancement treatmetns. Previously demonstrated results have been plotted agianst each other for better comparision.

One can notice the smooth decrease of monthly income of water flooding project, while other treatments decrease the income at the very early stages of the treatment (Figure 91). Main income from deep diverting gel project is achieved with simultaneous increase of oil production, whereas income increases with slower pace and lasts for longer time on polymer flooding project. Thus overall cashflow of both cases is very identical (Figure 92).

Main parameters from economic analysis are shown on table 16, where time, recovery and profit can be compared.

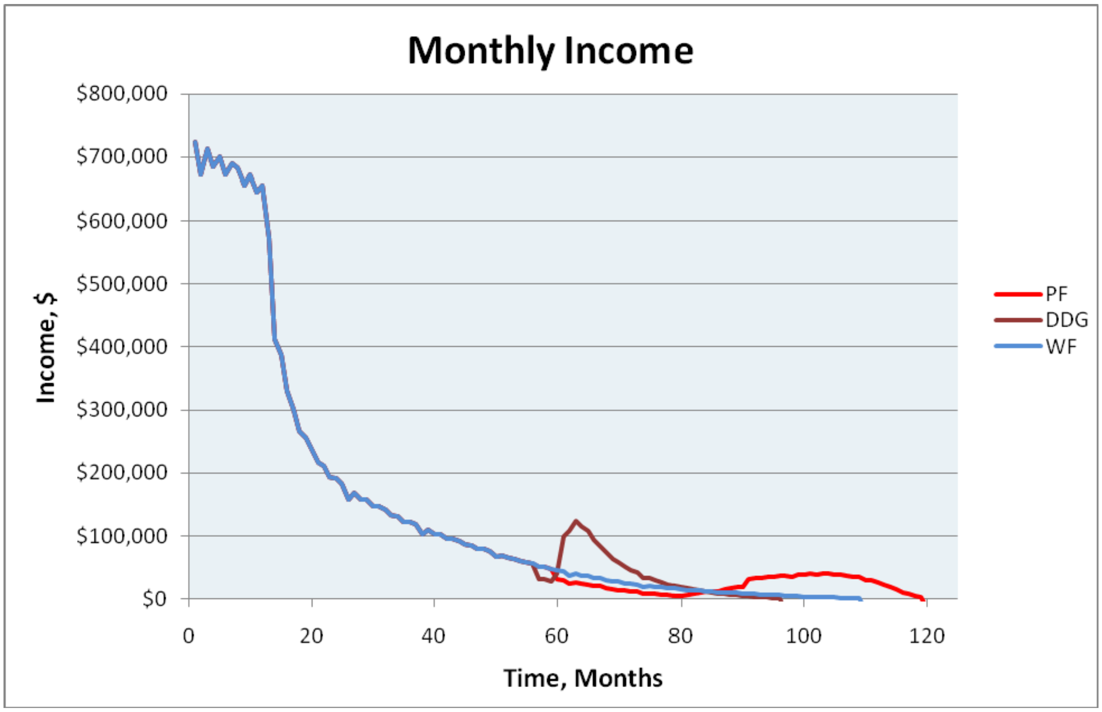

Figure 91 Comparison of monthly income

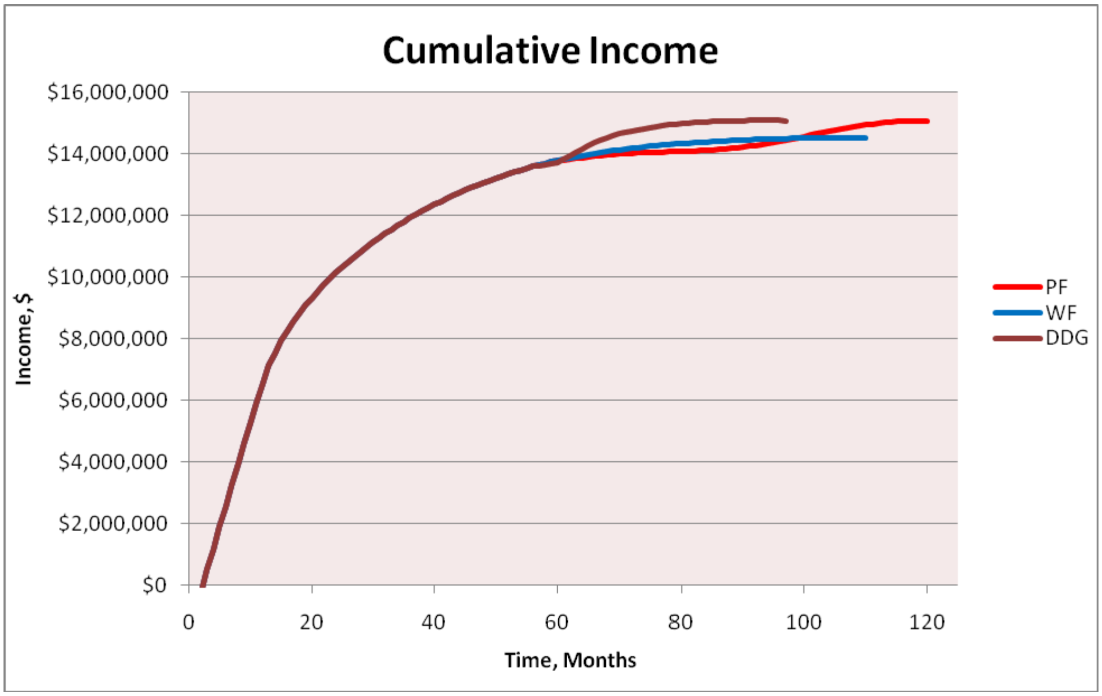

Figure 92 Comparison of total cash flow

Table 16 Quantitative comparison of all cases

		WF	*DDG*	*PF*
Well Life	*Years*	9.2	8.1	10.1
Total Production	*STB*	465,899	478,523	507,244
Recovery	*%*	50.59%	51.96%	55.08%
Total Cash Flow	*$*	$770,745	$1,393,581	$1,319,739

VIII CONCLUSIONS AND RECOMMENDATIONS

8.1 Conclusions

A simulation model of a quarter of a five-spot pattern has been developed for comparison of water flood, deep diverting gel and polymer flood recovery. Oil rates and cumulative recovery have been compared for the three processes from a starting point at 85% water cut to an assumed economic limit of 95% water cut. An economic spreadsheet was used to compare economics of the three processes. Modeling deep diverting gel was a major objective of this research since it was not an available option on commercial software. Water flooding and polymer flooding treatments have been included for comparison purposes. Schlumberger's Eclipse simulator was used to build the model. A spreadsheet was developed for economic analysis.

With respect to the base case water flooding project, the economic limit has been reached in a shorter time (i.e. field reaches 95% water cut more quickly and with greater oil recovery) with application of the deep diverting gels, whereas a polymer flood reaches 95% water cut at a later time than a water flood, with greater oil recovery than water flood or DDG flood.

Polymer concentration was the determinant of ultimate recovery in a polymer flood, so comparison of simulation runs with different polymer concentration was necessary to determine the optimal polymer flood. Results for three different polymer concentrations yielded increasing ultimate recovery with increasing polymer concentrations, but similar NPV, since increasing polymer concentration increases both cumulative production and polymer cost.

Although polymer flooding yields a higher oil recovery than water flooding or DDG treatment, this observation did not translate into better economics for the polymer flood. With assumed polymer concentrations and chemical costs deep diverting gels model results in similar cumulative cash flow as polymer flooding, while achieving it in shorter time period, which makes this treatment more favorable in terms of NPV compared to both water flooding and polymer flooding. Net present values after application of treatments with 10% discount rate has been determined for all 3 projects and were:

- Water flood: $770,745,
- Deep Diverting Gel: $1,393,581 and
- Polymer flood: $1,319,739.

Sensitivity runs on altered parameters of deep diverting gel model as a main focus of the research have been performed, but not analyzed economically. Change in treatment application time shows that it is favorable to block the high permeability zone at later stages of production, since the area and volume of the block increases due to the location of thermal front and yields a higher recovery and quicker production of additional oil. Creating larger blockage zone requires more chemical, thus economic analysis is required for more precise comparison of cases, but in terms of production, later application of the treatment shows better performance.

When the number of DDG plugs was increased, cumulative oil production increased by about 1-1.5% of OIP. Similarly, creating a larger plug increased oil recovery in the same range as observed on the case with two plugs. Results of these runs demonstrate that the more volume in high permeability zone blocked by the DDG plug, the higher the oil production will be. Effectiveness of each project can be estimated with broader economic investigation and designed accordingly, since NPV will be positively impacted by the additional oil, but negatively impacted by increased chemical costs.

Results of the same treatment may be more favorable in cases where more viscous oil present. In the case with 5 cp oil, recovery was increased by about 4% compared to 1.5% increase on base (2 cp oil) case.

The simulations in this project were run on a quarter of a 5 spot model; full pattern or field runs were not made. Thus it is important to note that in a field pilot or full field project, recovered oil and project NPV will be many multiples of those determined here. The critical conclusions here are the very significant increase in recovery factor and time to reach economic limit. Again, design and optimization of the treatment is very important factor determining economic success. Overall deep diverting gel appears to be a good method for increasing the recovery and can have a better performance than polymer flooding in some cases.

One of the main focuses of this research was to evaluate the novel chemical EOR technology and define possible expectations of different applications of it. Conclusions obtained from this research can be used as a basic idea to design the treatment according to different interests.

8.2 Recommendations

We realize that some of the assumptions we made for this research usually not observed in reality and there can be some work done to reduce the number of assumptions and make the model closer to realistic cases. Additionally, further work needs to be done to compare NPV of DDG treatments as a function of the amount of chemical used (size of blocking plug or plugs).

There are limitations about design of propagation and settlement of deep diverting gel particles. Especially some of the performed sensitivity runs have not been applied in real life and requires future work to be able to do so. Technical limitations need to be eliminated in order to achieve the results that we get from simulation runs.

We determined that viscosity of the reservoir oil is important factor determining the efficiency of DDG project, at least in the cases of 2 cp vs. 5 cp oil. DDG recovered more of the higher viscosity oil, but further work is required to determine whether this trend continues for even higher viscosity oils.

Simulation runs can be performed also for different types of heterogeneous reservoirs. Particularly by changing the location of high permeability layer to top or bottom of the reservoir effect of gravity segregation on treatment efficiency can be observed.

The simulation approach can be applied to model the behavior of deep diverting gels on different conditions. Economic analysis spreadsheet also can be applied to different cases where even deeper analysis required for the economics.

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APPENDIX

Data file of water flooding model in Eclipse.

```
-- Area of the pattern is 40 acres. Quarter of 5-spot represents 10 acres.
-- Two wells, one injector and one producer, on opposite sides of the 10 ac-pattern
-- Grid dimensions are 660 ft by 660 ft by 90 ft
-- Grid represents a 44x44x15 Cartesian model of a quarter of a 40 acre 5-spot

RUNSPEC

TEMP

-- Specifies the dimensions of the grid: 110x110x15
DIMENS
44 44 15 /

-- Specifies phases present: oil, water

OIL

WATER

-- Field units to be used
FIELD

-- Specifies dimensions of saturation and PVT tables
TABDIMS
1    1   30    30    1   30 /
```

```
-- Specifies maximum number of well and groups of wells
WELLDIMS
2    15    2    2 /

-- Specifies start of simulation
START
1 'JAN' 2000  /

-- Specifies the size of the stack for Newton iterations
NSTACK
50 /

GRID
=========================================================

-- Specifies the length of the cell in the X and Y
direction: 10 ft

DXV
2 42*15.61905 2 /

DYV
2 42*15.61905 2 /

-- Specifies the length of the cell in the X and Y
direction: 4 ft

DZ
29040*4 /

-- Specifies permeabilities in X direction: 100 md on
```

```
normal perm layers and 1200 on middle layer

BOX
1 44 1 44 1 5 /
PERMX
9680*100 /

BOX
1 44 1 44 6 10 /
PERMX
9680*1200 /

BOX
1 44 1 44 11 15 /
PERMX
9680*100 /

ENDBOX

-- Specifies permeabilities in Y direction: 100 md on
normal perm layers and 1200 on middle layer

BOX
1 44 1 44 1 5 /
PERMY
9680*100 /

BOX
1 44 1 44 6 10 /
PERMY
9680*1200 /
```

```
BOX
1 44 1 44 11 15 /
PERMY
9680*100 /

ENDBOX


-- Specifies permeabilities in Z direction: 10 md on
normal perm layers and 100 on middle layer

BOX
1 44 1 44 1 5 /
PERMZ
9680*10 /

BOX
1 44 1 44 6 10 /
PERMZ
9680*100 /

BOX
1 44 1 44 11 15 /
PERMZ
9680*10 /

ENDBOX


-- Specifies PorosityL 25%
```

```
BOX
1 44 1 44 1 5 /
PORO
9680*0.25 /

BOX
1 44 1 44 6 10 /
PORO
9680*0.25 /

BOX
1 44 1 44 11 15 /
PORO
9680*0.25 /

ENDBOX

-- Specifies the depth of the top cells: 8000 ft
TOPS
1936*8000.0 /

-- Specifies what is to be written in the GRID output file
RPTGRID
1 1 1 1 1 0 0 0 /

-- Allows for creating a GRID output file
GRIDFILE
2 1 /
```

```
-- Allows for creating an INIT output file
INIT



PROPS


==========================================================


-- Specifies water saturation tables: Water saturation,
Water relative permeability, Oil relative permeability
-- and Oil-Water capillary pressure



SWOF
Sw   krw            kro            Pcow


0.2  0              1              0
0.25 0.004346481    0.751314732    0
0.3  0.013763162    0.545761134    0
0.35 0.027010896    0.379858861    0
0.4  0.043581146    0.249999989    0
0.45 0.063161081    0.152424743    0
0.5  0.08553019     0.083187501    0
0.55 0.110520981    0.038106184    0
0.6  0.138000001    0.012679833    0
0.65 0.167857295    0.00193272     0
0.7  0.2       0         0
/


-- Specifies PVT properties of water: Bw = 1.063; Cw =
3.03E-06; watervisc = 0.7. All values at 3480 psia and
280 DegF
```

```
PVTW
3464  1  3.03E-06  .7  0.0 /


-- Specifies PVT properties of the oil: pressure, Bo and
oilvisc
PVDO


-- Pressure          Bo      Oil visc
     3480      1.01      2.0
     3600      1.00      2.0
/



--  Specifies  surface  densities:  Oil  API:  34.2;  Water
spec. gravity: 1.07;
GRAVITY
34.2  1.07 /


-- Specifies rock compressibility: 5.0E-06 psi -1 @ 3480
psia
ROCK
3480.0  5.0E-06 /


SPECHEAT
0.0 0.48 0.94 0.5
300.0 0.52 0.95 0.5
/


SPECRock
0.0 25
300 25 /
```

```
RTEMP
210 /


REGIONS
==========================================================


-- Specifies the number of saturation regions (only one
for this case)
SATNUM
29040*1 /


SOLUTION
==========================================================


-- Specifies initial equilibration conditions. Datum
depth = 8060 ft; Reference pressure at datum = 3480 psia
-- WOC depth = 15000 ft (out of the reservoir means no
initial contact present)
-- GOC depth = 0 ft (out of the reservoir means no
initial contact present)


EQUIL
8060  3480  15000  0   0   0   1   0   0  /


-- Specifies parameters to be written in the SOLUTION
section of the RESTART file: pressure, water saturation
-- gas saturation and oil saturation
RPTSOL
PRESSURE  SWAT SOIL FIP RPORV /


-- Specifies that RESTART files are to written every
timestep
RPTRST
```

```
BASIC=2 /


SUMMARY
=========================================================


-- Specifies that a SUMMARY file with neat tables is to
be written in text format
RUNSUM


-- Specifies that the SUMMARY file is to be created as a
separate file in addition from the text file with neat
tables
SEPARATE


-- Specifies that reports are to be written only at the
timesteps specified in the DATA file. Avoids reports to
-- be created at chopped timesteps (to avoid excessive
data and clutter).
RPTONLY



-- Specifies that a group of parameters specific to
ECLIPSE are going to be written in the SUMMARY files.


ALL
EXCEL
separate
ALL


FOE
/


SCHEDULE
```

```
==========================================================

-- Specifies what is to written to the SCHEDULE file
RPTSCHED                                              FIELD
16:55 18 APR 86
1  0  1  0  0  0  2  0  0  0  0  2  0  0  0  0

0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0

0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0/

-- Define well specifications:

WELSPECS
'P'  'G'    44  1  8030  'OIL' 2* SHUT /
'I'  'G'    1  44  8030  'WAT'  /
/



-- Specifies completion data
COMPDAT
'P'    44   1   1   15 'OPEN'   1  0   .27 3* z /

'I'    1   44   1   15 'OPEN'   1  0   .27 3* z /
/

-- Specifies well controls for the producer
-- Name of the well: P
-- Status of the well: open to production
-- Well control mode: reservoir voidage rate
--  The  final  record  specifies  target  for  the  control
```

```
parameter: 500 reservoir barrels

WCONPROD
'P' 'OPEN' 'LRAT' 3* 500 /
/

-- Specifies well controls for the injector
-- Name of the well: I
-- Status of the well: open to injection
-- Well control mode: reservoir injection rate
-- The final record specifies target for the control parameter: 500 reservoir barrels

WCONINJ
'I' 'WATER' 'OPEN' 'RATE' 500 /
/
WECON
'P' 2* 0.95 2* WELL YES/
/
WTEMP
'I' 70 /
/

TUNING
/
/
2* 100/

-- Specifies the number and length of the timesteps required. Each timestep has been selected according to number of days each month to obtain monthly rates for further economic analysis.
```

```
TSTEP
0.1 0.3 0.6 1 3 5 21 29 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
31 29 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
31 29 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
31 29 31 30 31 30 31 31 30 31 30 31 /
END
```

Permeability inputs of plugged cells in data file of deep diverting gel model

```
-- Specifies permeabilities of plugged cells in X
direction: 40 md

BOX
1 29 5 5 6 10 /
PERMX
145*40 /

BOX
1 31 6 6 6 10 /
PERMX
155*40 /

BOX
1 34 7 7 6 10 /
PERMX
170*40 /

BOX
1 36 8 8 6 10 /
PERMX
180*40 /

BOX
30 37 9 9 6 10 /
PERMX
40*40 /

BOX
```

```
32 37 10 10 6 10 /
PERMX
30*40 /

BOX
34 38 11 11 6 10 /
PERMX
25*40 /

BOX
35 38 12 13 6 10 /
PERMX
40*40 /

BOX
36 39 14 15 6 10 /
PERMX
40*40 /

BOX
37 40 16 44 6 10 /
PERMX
580*40 /

ENDBOX

-- Specifies permeabilities of plugged cells in Y
direction: 40 md

BOX
1 29 5 5 6 10 /
```

```
PERMY
145*40 /

BOX
1 31 6 6 6 10 /
PERMY
155*40 /

BOX
1 34 7 7 6 10 /
PERMY
170*40 /

BOX
1 36 8 8 6 10 /
PERMY
180*40 /

BOX
30 37 9 9 6 10 /
PERMY
40*40 /

BOX
32 37 10 10 6 10 /
PERMY
30*40 /

BOX
34 38 11 11 6 10 /
PERMY
```

```
25*40 /

BOX
35 38 12 13 6 10 /
PERMY
40*40 /

BOX
36 39 14 15 6 10 /
PERMY
40*40 /

BOX
37 40 16 44 6 10 /
PERMY
580*40 /
ENDBOX

-- Specifies permeabilities of plugged cells in Z direction: 10 md

BOX
1 29 5 5 6 10 /
PERMZ
145*10 /

BOX
1 31 6 6 6 10 /
PERMZ
155*10 /
```

```
BOX
1 34 7 7 6 10 /
PERMZ
170*10 /

BOX
1 36 8 8 6 10 /
PERMZ
180*10 /

BOX
30 37 9 9 6 10 /
PERMZ
40*10 /

BOX
32 37 10 10 6 10 /
PERMZ
30*10 /

BOX
34 38 11 11 6 10 /
PERMZ
25*10 /

BOX
35 38 12 13 6 10 /
PERMZ
40*10 /

BOX
```

```
36 39 14 15 6 10 /
PERMZ
40*10 /

BOX
37 40 16 44 6 10 /
PERMZ
580*10 /

ENDBOX
```

Production and Injection Rate Inputs of Economic Analysis spreadsheet.

WF			Polymer flooding				DDG			
Produced		Injected	Produced		Injected		Produced		Injected	
Oil STB	**Water bbl**	**Water bbl**	**Oil STB**	**Water bbl**	**Water bbl**	**Polymer lb**	**Oil STB**	**Water bbl**	**Water bbl**	**Polymer lb**
15500	0.33	15500	15500	0.33	15500	0.00	15500	0.33	15500	0.00
14500	0.25	14500	14500	0.25	14500	0.00	14500	0.25	14500	0.00
15500	0.26	15500	15500	0.26	15500	0.00	15500	0.26	15500	0.00
15000	0.24	15000	15000	0.24	15000	0.00	15000	0.24	15000	0.00
15500	0.25	15500	15500	0.25	15500	0.00	15500	0.25	15500	0.00
15000	0.25	15000	15000	0.25	15000	0.00	15000	0.25	15000	0.00
15500	0.27	15500	15500	0.27	15500	0.00	15500	0.27	15500	0.00
15500	0.28	15500	15500	0.28	15500	0.00	15500	0.28	15500	0.00
15000	0.29	15000	15000	0.29	15000	0.00	15000	0.29	15000	0.00
15500	0.32	15500	15500	0.32	15500	0.00	15500	0.32	15500	0.00
15000	0.38	15000	15000	0.38	15000	0.00	15000	0.38	15000	0.00
15402	97.84	15500	15402	97.84	15500	0.00	15402	97.84	15500	0.00
13620	1879.82	15500	13620	1879.82	15500	0.00	13620	1879.82	15500	0.00
10020	3979.85	14000	10020	3979.85	14000	0.00	10020	3979.85	14000	0.00
9593	5906.80	15500	9593	5906.80	15500	0.00	9593	5906.80	15500	0.00
8318	6681.82	15000	8318	6681.82	15000	0.00	8318	6681.82	15000	0.00
7722	7778.27	15500	7722	7778.27	15500	0.00	7722	7778.27	15500	0.00
6974	8025.90	15000	6974	8025.90	15000	0.00	6974	8025.90	15000	0.00
6770	8729.86	15500	6770	8729.86	15500	0.00	6770	8729.86	15500	0.00
6410	9090.15	15500	6410	9090.15	15500	0.00	6410	9090.15	15500	0.00
5920	9079.69	15000	5920	9079.69	15000	0.00	5920	9079.69	15000	0.00
5858	9641.63	15500	5858	9641.63	15500	0.00	5858	9641.63	15500	0.00
5459	9541.36	15000	5459	9541.36	15000	0.00	5459	9541.36	15000	0.00
5444	10056.23	15500	5444	10056.23	15500	0.00	5444	10056.23	15500	0.00
5271	10228.55	15500	5271	10228.55	15500	0.00	5271	10228.55	15500	0.00
4636	9364.30	14000	4636	9364.30	14000	0.00	4636	9364.30	14000	0.00
4996	10504.40	15500	4996	10504.40	15500	0.00	4996	10504.40	15500	0.00
4719	10280.60	15000	4719	10280.60	15000	0.00	4719	10280.60	15000	0.00
4764	10735.60	15500	4764	10735.60	15500	0.00	4764	10735.60	15500	0.00
4512	10488.50	15000	4512	10488.50	15000	0.00	4512	10488.50	15000	0.00
4559	10941.50	15500	4559	10941.50	15500	0.00	4559	10941.50	15500	0.00
4456	11044.20	15500	4456	11044.20	15500	0.00	4456	11044.20	15500	0.00
4217	10782.90	15000	4217	10782.90	15000	0.00	4217	10782.90	15000	0.00

4258	11241.50	15500	4258	11241.50	15500	0.00	4258	11241.50	15500	0.00
4031	10969.40	15000	4031	10969.40	15000	0.00	4031	10969.40	15000	0.00
4071	11429.40	15500	4071	11429.40	15500	0.00	4071	11429.40	15500	0.00
3980	11519.70	15500	3980	11519.70	15500	0.00	3980	11519.70	15500	0.00
3524	10476.30	14000	3524	10476.30	14000	0.00	3524	10476.30	14000	0.00
3816	11684.00	15500	3816	11684.00	15500	0.00	3816	11684.00	15500	0.00
3615	11385.50	15000	3615	11385.50	15000	0.00	3615	11385.50	15000	0.00
3653	11847.10	15500	3653	11847.10	15500	0.00	3653	11847.10	15500	0.00
3461	11539.40	15000	3461	11539.40	15000	0.00	3461	11539.40	15000	0.00
3499	12001.10	15500	3499	12001.10	15500	0.00	3499	12001.10	15500	0.00
3422	12077.90	15500	3422	12077.90	15500	0.00	3422	12077.90	15500	0.00
3237	11762.90	15000	3237	11762.90	15000	0.00	3237	11762.90	15000	0.00
3262	12237.60	15500	3262	12237.60	15500	0.00	3262	12237.60	15500	0.00
3080	11920.40	15000	3080	11920.40	15000	0.00	3080	11920.40	15000	0.00
3101	12399.40	15500	3101	12399.40	15500	0.00	3101	12399.40	15500	0.00
3022	12477.90	15500	3022	12477.90	15500	0.00	3022	12477.90	15500	0.00
2762	11738.30	14500	2762	11738.30	14500	0.00	2762	11738.30	14500	0.00
2878	12622.10	15500	2878	12622.10	15500	0.00	2878	12622.10	15500	0.00
2716	12283.90	15000	2716	12283.90	15000	0.00	2716	12283.90	15000	0.00
2737	12763.00	15500	2737	12763.00	15500	0.00	2737	12763.00	15500	0.00
2584	12415.70	15000	2584	12415.70	15000	0.00	2584	12415.70	15000	0.00
2603	12897.50	15500	2603	12897.50	15500	0.00	2603	12897.50	15500	0.00
2534	12966.30	15500	2534	12966.30	15500	0.00	2534	12966.30	15500	10850
2384	12616.20	15000	2384	12616.20	15000	0.00	2384	12616.20	15000	10500
2391	13109.10	15500	2391	13109.10	15500	0.00	2391	13109.10	15500	10850
2246	12754.10	15000	2246	12754.10	15000	0.00	2246	12754.10	15000	10500
2253	13247.50	15500	2254	13045.70	15300	5355	2740	12752.50	15500	10850
2190	13309.80	15500	2222	13277.90	15500	5425.00	4080	11420.40	15500	0.00
1930	12069.70	14000	1958	12042.40	14000	4900.00	4321	9678.70	14000	0.00
2083	13417.30	15500	2117	13383.20	15500	5425.00	4937	10563.20	15500	0.00
1966	13033.50	15000	2002	12997.80	15000	5250.00	4638	10362.50	15000	0.00
1979	13521.40	15500	2021	13478.80	15500	5425.00	4483	11017.20	15500	0.00
1865	13135.40	15000	1911	13088.70	15000	5250.00	3977	11023.00	15000	0.00
1871	13629.10	15500	1925	13574.70	15500	5425.00	3656	11843.80	15500	0.00
1814	13686.30	15500	1866	13633.80	15500	5425.00	3345	12155.30	15500	0.00
1703	13296.80	15000	1744	13256.50	15000	5250.00	2981	12019.10	15000	0.00
1713	13786.80	15500	1747	13752.80	15500	5425.00	2838	12661.90	15500	0.00
1617	13383.40	15000	1653	13347.30	15000	5250.00	2546	12454.40	15000	0.00
1628	13871.80	15500	1670	13830.40	15500	5425.00	2438	13062.30	15500	0.00
1589	13911.20	15500	1632	13867.90	15500	5425.00	2265	13234.60	15500	0.00

1405	12595.10	14000	1445	12555.50	14000	4900.00	1920	12079.80	14000	0.00
1519	13981.00	15500	1566	13933.80	15500	5425.00	1989	13511.50	15500	0.00
1436	13564.00	15000	1484	13516.30	15000	5250.00	1808	13191.90	15000	0.00
1448	14052.00	15500	1500	14000.00	15500	5425.00	1757	13743.30	15500	0.00
1369	13631.20	15000	1420	13580.10	15000	5250.00	1605	13394.80	15000	0.00
1382	14117.70	15500	1441	14058.70	15500	5425.00	1567	13933.00	15500	0.00
1351	14148.60	15500	1441	14059.30	15500	5425.00	1484	14016.20	15500	0.00
1280	13719.70	15000	1463	13537.50	15000	5250.00	1365	13635.20	15000	0.00
1295	14205.50	15500	1580	13919.90	15500	5425.00	1341	14158.80	15500	0.00
1227	13772.80	15000	1583	13417.30	15000	5250.00	1238	13761.60	15000	0.00
1241	14258.70	15500	1686	13813.90	15500	5425.00	1221	14279.50	15500	0.00
1216	14284.20	15500	1741	13759.40	15500	5425.00	1166	14333.60	15500	0.00
1078	12922.10	14000	1630	12370.00	14000	4900.00	1013	12987.40	14000	0.00
1169	14330.80	15500	1879	13621.40	15500	5425.00	1075	14425.00	15500	0.00
1109	13890.70	15000	1885	13114.70	15000	5250.00	1000	13999.80	15000	0.00
1125	14375.50	15500	2013	13486.60	15500	5425.00	994	14506.00	15500	0.00
1068	13931.60	15000	2034	13165.50	15200	5250.00	927	14073.00	15000	0.00
1083	14417.00	15500	2104	13196.60	15300	0.00	923	14577.00	15500	0.00
1062	14437.70	15500	2180	13320.20	15500	0.00	891	14609.50	15500	0.00
1009	13991.10	15000	2155	12845.10	15000	0.00	834	14166.30	15000	0.00
1023	14477.00	15500	2277	13223.50	15500	0.00	834	14666.30	15500	0.00
972	14028.10	15000	2254	12745.80	15000	0.00	782	14217.70	15000	0.00
986	14514.30	15500	2381	13119.00	15500	0.00	784	14716.10	15500	0.00
967	14533.00	15500	2428	13071.40	15500	0.00	761	14739.00	15500	0.00
889	13611.00	14500	2313	12188.00	14500	0.00				
933	14567.00	15500	2514	12986.00	15500	0.00				
887	14114.00	15000	2469	12531.00	15000	0.00				
900	14600.00	15500	2583	12917.00	15500	0.00				
855	14145.00	15000	2523	12477.00	15000	0.00				
868	14632.00	15500	2623	12877.00	15500	0.00				
853	14647.00	15500	2627	12873.00	15500	0.00				
811	14188.00	15000	2532	12468.00	15000	0.00				
824	14676.00	15500	2593	12907.00	15500	0.00				
784	14217.00	15000	2473	12527.00	15000	0.00				
796	14704.00	15500	2507	12993.00	15500	0.00				
782	14717.00	15500	2443	13057.00	15500	0.00				
696	13305.00	14000	2134	11866.00	14000	0.00				
			2,250	13250.00	15,500	0.00				
			2,034	12966.00	15,000	0.00				
			1,919	13582.00	15,500	0.00				

			1,653	13347.00	15,000	0.00				
			1,496	14004.00	15,500	0.00				
			1,309	14191.00	15,500	0.00				
			1,110	13890.00	15,000	0.00				
			1,006	14494.00	15,500	0.00				
			866	14133.00	15,000	0.00				
			814	14686.00	15,500	0.00				
			125	2375.00		0.00				

VITA

Seyidov Murad was born in Baku, Azerbaijan. He attended "Turkiye Diyanet Vakfi" Turkish lyceum in Baku. He graduated from high school in 2003 and started that same year attending Azerbaijan State Oil Academy in Baku. During his time at ASOA, he worked as a lab assistant. He received his B.S. in petroleum engineering from Azerbaijan State Oil Academy in 2007. After his junior and senior years he did two internships for BP Azerbaijan. In 2007, he started attending Texas A&M University for M.S. in petroleum engineering and received his M.S. in 2010. For contact information, Murad can be reached at murad_seyidov@hotmail.com. His permanent address is Yeni Yasamal 1, bldg 12, apt 80., Baku, Azerbaijan AZ 1012.